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Course 427: Combustion Evaluation
Student Manual

Associated Environmental Consultants
Charlottesville, VA

Prepared for

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Combustion Evaluation

Student Manual

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16. ABSTRACT

This Student Manual is used in conjunction with Course #427, "Combustion Evaluation" as applied to air pollution control situations. The manual was prepared by the EPA Air Pollution Training Institute (APTI) to supplement the course lecture materials and to present detailed reference information on the following topics:

- Combustion fundamentals
- Fuel properties
- Combustion system design
- Pollutant emission evaluations
- Combustion control
- Gas, oil & coal burning
- Solid waste & wood burning
- Incineration of wastes
- Sewage sludge incineration
- Flame and catalytic incineration
- Waste gas flares
- Hazardous waste combustion
- NO_x control and
- Improved combustion systems

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Note: There is also an Instructor's Guide to be used in conducting the training course - (EPA-450/2-80-065) and a Student Workbook to be used for homework and in-class problem solving - (EPA-450/2-80-64).

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Notice

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AIR POLLUTION TRAINING INSTITUTE
MANPOWER AND TECHNICAL INFORMATION BRANCH
CONTROL PROGRAMS DEVELOPMENT DIVISION
OFFICE OF AIR QUALITY PLANNING AND STANDARDS

The Air Pollution Training Institute (1) conducts training for personnel working on the development and improvement of state, and local governmental, and EPA air pollution control programs, as well as for personnel in industry and academic institutions; (2) provides consultation and other training assistance to governmental agencies, educational institutions, industrial organizations, and others engaged in air pollution training activities; and (3) promotes the development and improvement of air pollution training programs in educational institutions and state, regional, and local governmental air pollution control agencies. Much of the program is now conducted by an on-site contractor, Northrop Services, Inc.

One of the principal mechanisms utilized to meet the Institute's goals is the intensive short term technical training course. A full-time professional staff is responsible for the design, development, and presentation of these courses. In addition the services of scientists, engineers, and specialists from other EPA programs governmental agencies, industries, and universities are used to augment and reinforce the Institute staff in the development and presentation of technical material.

Individual course objectives and desired learning outcomes are delineated to meet specific program needs through training. Subject matter areas covered include air pollution source studies, atmospheric dispersion, and air quality management. These courses are presented in the Institute's resident classrooms and laboratories and at various field locations.

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Chapter 1

Introduction to Combustion Evaluation in Air Pollution Control

Air pollution is caused by both natural and mechanical sources. In urban areas, where ambient air pollution levels are highest, the majority of the emissions are from stationary and mobile combustion sources. Emissions include particulates and gaseous chemicals which damage both the public health and the general welfare.

Combustion Evaluation in Air Pollution Control presents the fundamental and applied aspects of state-of-the-art combustion technology, which influence the control of air pollutant emissions. Emphasis will be placed on controlling combustion in order to minimize emissions, rather than on the well known combustion gas cleaning techniques (which are adequately presented elsewhere).

To summarize, the goals of *Combustion Evaluation in Air Pollution Control* are to provide engineers, technical and regulatory officials, and others with knowledge of the fundamental and applied aspects of combustion, as well as an overview of the state-of-the-art of combustion technology as it relates to air pollution control work.

In order to achieve these goals, emphasis will be on calculations, as well as design and operational considerations for those combustion sources and control devices which are frequently encountered, including:

a. Combustion sources burning fossil fuel for the generation of steam or direct heat;
b. Combustion sources burning liquid and solid waste; and
c. Pollution control devices which utilize combustion for the control of gaseous and aerosol pollutants.

Students will become familiar with combustion principles as well as the more important design and operational parameters influencing air pollution emissions from typical combustion sources. Further, they will be able to perform selected fundamental calculations related to the quantities of emissions and the requirements for complete combustion. Participants will understand some of the more important mechanisms by which trace species are formed in and emitted by stationary combustion processes. The students will understand the ways in which certain design and operation variables may be set to minimize emissions.

An individual assimilating the knowledge described above will have the ability to perform work with combustion-related pollution problems: evaluate actual and potential emissions from combustion sources; perform engineering inspections; and develop recommendations to improve the performance of malfunctioning combustion equipment.

The detailed instructional objectives, which are presented in Appendix 1-1, are discussed below.

The basic factors affecting the completeness of fuel combustion (oxygen, time, temperature, and turbulence) are important concepts which must be understood in any evaluation of combustion. The consequences of poor combustion include the emission of smoke, particulates, carbon monoxide, and other unoxidized or partially oxidized hydrocarbon gases.

Fundamental concepts must be considered in the analysis of combustion-related air pollution problems. For example: the temperature of a fuel oil establishes its viscosity; viscosity (and other design variables) determines the atomized-droplet size in an oil burner; droplet size influences evaporation rate, which in turn sets the time requirements for complete combustion. Another important consideration is the formation of NO_X, which may be reduced by limiting the excess air in the combustion zone.

Combustion calculations will be derived from fundamental concepts of chemistry and thermodynamics. Many computational examples will be presented, using algebraic equations with tabulated property and standard factor values. Particular emphasis will be on practical calculations which are typically required for the review of combustion installations and to determine compliance with emission standards.

Other important factors used to reduce pollutant emissions are equipment design and operational characteristics. A physical understanding of these characteristics will be used to determine the corrective action needed for malfunctioning combustion equipment. Common stationary combustion sources will be described. These include (a) fuel combustion equipment for natural gas, fuel oil, coal, and wood; (b) waste gas combustion equipment, including flares, catalytic incinerators, and direct-flame incinerators; and (c) solid waste combustion equipment designed to burn garbage, industrial waste gas, municipal sewage sludge, and various potentially hazardous chemical waste materials.

When these instructional objectives have been successfully accomplished, individuals will be (a) familiar with combustion principles, (b) able to perform calculations, (c) able to describe formation of air pollution from combustion sources, and (d) able to make recommendations for improving emissions from combustion sources.

Appendix 1-1

Instructional Objectives For Combustion Evaluation in Air Pollution Control

1. Subject: Introduction to Combustion Evaluation in Air Pollution Control

   Objective: The student will be able to:

   a. Identify three major goals of Combustion Evaluation in Air Pollution Control;

   b. List four of the subject areas which will be emphasized in the course (fundamentals of combustion, fuel properties, combustion system design, emission calculations, various combustion equipment topics, NO_X control);

   c. Present two reasons for applying the fundamental concepts of combustion when solving combustion evaluation problems in air pollution control;

   d. List three of the important air pollutant emissions which may be limited by combustion control.

2. Subject: Fundamentals of Combustion

   Objective: The student will be able to:

   a. Use the basic chemical equations for combustion reactions, with or without excess air, to calculate air requirements and amount of combustion products;

   b. Apply the ideal gas law to determine volumetric relationships for typical combustion situations;

   c. Distinguish between different types of combustion as characterized by carbonic theory (yellow flame) and hydroxylation theory (blue flame);

   d. Define heat of combustion, gross and net heating values, available heat, hypothetical available heat, sensible heat, latent heat, and heat content;

   e. Determine the available heat obtained from burning fuels at different flue gas exit temperatures and with various amounts of excess air, using generalized correlations;

   f. List the chemical elements which combine with oxygen when fuels burn;

   g. List the four items necessary for efficient combustion;

   h. Describe qualitatively the interrelationships between time, temperature, turbulence, and oxygen required for proper combustion of a given fuel;

i. Recite the conditions for equilibrium;

j. Describe how an excess quantity of one reactant will affect other concentrations at equilibrium;

k. Cite the expression for the rate of reaction;

l. Identify the Arrhenius equation as a model for the influence of temperature on combustion rate;

m. Define the activation energy;

n. Describe the mechanism of catalytic activity; and

o. List the reasons for the deterioration of catalytic activity.

3. Subject: Fuel Properties

Objectives: The student will be able to:

a. State the important chemical properties which influence air pollutant emissions;

b. Use the tables in the student manual to find representative values for given fuel properties;

c. Describe the difference in physical features which limit the rate of combustion for gaseous, liquid, and solid fuels;

d. Explain the importance of fuel properties such as flash point and upper and lower flammability limits which relate to safe operation of combustion installations;

e. Use either specific or API gravity to determine the total heat of combustion of a fuel oil;

f. Describe the influence of variations in fuel oil viscosity on droplet formation and on completeness of combustion and emissions;

g. List the important components in the proximate and ultimate analyses;

h. Define "as fired," "as received," "moisture free," and "dry basis" as they apply to the chemical analysis of solid fuels; and

i. Explain the significance of ash fusion temperature and caking index in the burning of coal.

4. Subject: Combustion System Design

Objectives: The student should be able to:

a. Describe the relationship between energy utilization, furnace heat transfer, and excess air as means of furnace temperature control;

b. Understand the limits which may be imposed by thermodynamic laws and how these limits dictate choice of energy-recovery devices following the furnace; and

c. Calculate the energy required from fuel to meet an output energy requirement.

5. Subject: Pollution Emission Calculations
   Objective: The student should be able to:
   a. Describe the nature and origin of most of the published emission factors and state what is necessary for more precise estimates of emissions from a specific installation with specified design features;
   b. Apply the proper method for using emission factors to determine estimates of emissions from typical combustion sources;
   c. Define and distinguish between concentration standards (C_{vs} and C_{ms}), pollutant mass rate standards (PMR_s), and process standards (E_s);
   d. Use average emission factors to estimate the emissions from typical combustion installations;
   e. Calculate the degree of control required for a given source to be brought into compliance with a given emission standard;
   f. Perform calculations using the relationships between anticipated SO_2 emissions and the sulfur content of liquid and solid fuels;
   g. Identify the proper equation for computing excess air from an Orsat analysis of the flue gas of a combustion installation;
   h. State the reasons for expressing concentrations at standard conditions of temperature pressure, moisture content, and excess air;
   i. Identify and use the proper factors for correcting field measurements to a standard basis, such as 50% excess air 12% CO_2, and 6% O_2; and
   j. Use F-factors to estimate emissions from a combustion source.

6. Subject: Combustion Control and Instrumentation
   Objective: The student will be able to:
   a. List the important variables (steam pressure, steam flow rate, gas temperature) which may serve as the controlled variables used to actuate fuel/air controls for combustion systems;
   b. Describe the primary purpose of a control system which is to maintain combustion efficiency and thermal states;
   c. Understand the interrelationships between varying load (energy output) requirements and both fuel/air flow and excess air;
   d. Identify instrument readings indicating improper combustion or energy transfer; and
   e. Describe the influence of excess air (indicated by O_2 in stack gases) on the boiler efficiency, fuel rate, and economics of a particular boiler installation.

7. Subject: Gaseous Fuel Burning
   Objective: The student will be able to:
   a. Describe the functions of the gas burner;
   b. Define pre-mix and its influence on the type of flame;
   c. List burner design features and how these affect the limits of stable flame operating region;

d. Name four different types of gas burners and their special design features;

e. Cite typical gas furnace, breeching and stack operating temperatures, pressures, and gas flow velocities;

f. Describe the relationship between flue gas analyses and air-to-fuel ratio;

g. List the causes and describe the signs of malfunctioning gas-burning devices; and

h. Describe techniques used to correct a malfunctioning gas-burning device.

8. Subject: Fuel Oil Burning
Objective: The student will be able to:

a. Describe the important design and emission characteristics of oil burners using air, steam, mechanical (pressure), and rotary-cup atomization;

b. Describe the influence of temperature on oil viscosity and atomization;

c. Describe how vanadium and sulfur content in fuel oil influence furnace corrosion and air pollution emissions;

d. Describe burner nozzle maintenance and its influence on air pollutant emissions from oil combustion installations; and

e. Locate and use tabulated values of oil fuel properties and pollutant factors to compute uncontrolled emissions from oil-burning sources.

9. Subject: Coal Burning
Objective: The student will be able to:

a. Describe the design characteristics and operating practice of coal burning equipment, including overfeed, underfeed, and spreader stokers, as well as pulverized and cyclone furnaces;

b. Discuss the parameters that influence the design of overfire and underfire air (in systems which burn coal on grates) and for primary and secondary air (in systems which burn coal in suspension);

c. Describe the influence of the amount of volatile matter and fixed carbon in the coal on its proper firing in a given furnace design; and

d. Describe how changing the ash content and the heating value of coal can influence the combustion as well as the capacity of a specified steam generator.

10. Subject: Solid Waste and Wood Burning
Objective: The student will be able to:

a. List the important similarities and differences in both physical and chemical properties of solid waste, wood waste, and coal;

b. Describe the mechanical configurations required to complete combustion of solid waste and wood waste and compare with those for burning coal; and

c. Describe the unique combustion characteristics and emissions from burning unprepared solid waste and refuse-derived fuel.

11. Subject: Controlled-Air Incineration

Objective: The student will be able to:

a. Describe the combustion principles and pollution emission characteristics of controlled-air incinerators contrasted with those of single and multiple-chamber designs;

b. Identify operating features which may cause smoke emission from controlled-air incinerators; and

c. Relate the temperature of gases leaving the afterburner to the amount of auxiliary fuel needed by the afterburner.

12. Subject: Municipal Sewage Sludge Incineration (Optional)

Objective: The student will be able to:

a. List and discuss the air pollutants emitted in incineration of sewage sludge;

b. Describe special design features required to burn wet sewage sludge fuel;

c. Describe the combustion-related activity occurring in each of the four zones of the multiple-hearth sewage sludge incinerators;

d. Discuss the options of combustion air preheating, flue gas reheating, and energy recovery; and

e. List two important operational problems which can adversely influence air pollution emissions.

13. Subject: Direct-Flame and Catalytic Incineration

Objective: The student will be able to:

a. Cite examples of air pollution sources where direct-flame and catalytic afterburners are used to control gaseous emissions;

b. Describe the influence of temperature on the residence time required for proper operation of afterburners;

c. Apply fundamental combustion calculations to determine the auxiliary fuel required for direct-flame and catalytic incineration with and without energy recovery;

d. Perform the necessary calculations to determine the proper physical dimensions of an afterburner for a specific application;

e. List three reasons for loss of catalytic activity and ways of preventing such loss; and

f. Cite methods available for reducing afterburner operating costs.

14. Subject: Waste Gas Flares (Optional)

Objective: The student will be able to:

a. Calculate the carbon-to-hydrogen ratio of a waste-gas stream and determine when and how much steam will be required for smokeless flare operation;

b. Understand the difference between elevated and ground-level flares and the design considerations which underlie the choice of one or the other; and

c. Describe provisions for leveling waste gas flow rates from intermittent sources.

15. Subject: Combustion of Hazardous Wastes

Objective: The student will be able to:

a. Cite special requirements associated with the combustion of hazardous liquid and solid wastes;

b. Recite the special requirements for treating the combustion products to control pollutant emissions from incineration operations;

c. List examples of substances and/or elements which cannot be controlled by incineration;

d. Describe the fuel requirements necessary to dispose of hazardous waste materials; and

e. List a number of hazardous waste materials (including polychlorinated biphenyls--PCBs--pesticides, and some other halogenated organics) which may be disposed of successfully through proper liquid incineration devices; give the required temperatures and residence times to achieve adequate destruction.

16. Subject: NO_x Control

Objective: The student will be able to:

a. Identify three of the major stationary sources of NO_x emissions;

b. Locate and use emission factors to estimate the amount of NO_x emitted by a potential combustion source;

c. Describe the difference between mechanisms for forming "Thermal NO_x" and "Fuel NO_x";

d. Describe various techniques for NO_x control: flue-gas recirculation, two-stage combustion, excess air control, catalytic dissociation, wet-scrubbing, water injection, and reduced fuel burning rate; and

e. State the amount of NO_x control available from particular examples of combustion modification.

17. Subject: Improved Combustion through Design Modification

Objective: The student will be able to:

a. State the benefits of proper maintenance and adjustment of residential oil-combustion units;

b. List three important features to check during the maintenance of commercial oil-fired burners;

c. Discuss the difference between "minimum O_2" and "lowest practical O_2" and why these are important in industrial boilers;

d. List two reasons why a burner may have a higher "minimum O_2" level than the typical value; describe what remedies may be available;

e. Indicate the effect of the combustion modification techniques on thermal efficiency: lowering excess air, staged air combustion; reduced combustion-air preheat, and flue-gas recirculation; and

f. Discuss why NO_X control from coal-fired utility boilers is more difficult to achieve than from similar oil or gas units.

Chapter 2

Fundamentals of Combustion

INTRODUCTION

Combustion is a chemical reaction. It is the rapid oxidation of combustible substances accompanied by the release of energy (heat and light) while the constituent elements are converted to their respective oxides.

The products of complete combustion of hydrocarbon fuels are innocuous carbon dioxide and water vapor. Incomplete combustion, however, can lead to serious air pollution problems with the emissions of smoke, carbon monoxide, and/or other partially oxidized products, and should therefore be avoided. Further, should the fuel contain elements such as sulfur and nitrogen, then the flue gases will contain their respective oxides as pollutants, even with complete combustion. Chapter 16 describes thermal NO_X and fuel NO_X.

To achieve efficient combustion with a minimum of air pollutant emissions, it is essential that the proper amount of air be available to the combustion chamber and that adequate provision be made for the disposal of the flue gases. Other factors influencing the completeness of combustion are temperature, time, and turbulence. These are sometimes referred to as the "three T's of combustion," and need to be given careful consideration when evaluating existing or proposed combustion processes, as well as designs for new installations.

Each combustible substance has a characteristic minimum ignition temperature which must be attained or exceeded, in the presence of oxygen, for the oxidation reaction to proceed at a rate which would qualify it as combustion. Above the ignition temperature heat is generated at a higher rate than its losses to the surroundings which makes it possible to maintain the elevated temperatures necessary for sustained combustion.

Time is a fundamental factor in the design, which influences the performance of combustion equipment. The residence time of a fuel particle in the high-temperature region should exceed the time required the combustion of that particle to take place. This will therefore set constraints on the size and shape of the furnace for a desired fuel firing rate. Since the reaction rate increases with increasing temperature, the time required for combustion will be less at higher temperatures, thus raising an economic question for the designer: the smaller the unit, the higher the temperature must be to oxidize the material in the residence time available.

Turbulence and the resultant mixing of fuel and oxygen are also essential for efficient combustion processes. Inadequate mixing of combustible gases and air in the furnace can lead to emissions of incomplete combustion products, even from an otherwise properly sized unit with sufficient oxygen. Turbulence will speed up the evaporation of liquid fuels for combustion in the vapor phase. In case of solid fuels, turbulence will help to break up the boundary layer of combustion products formed around the burning particle which would otherwise cause the slowing down of the combustion rate by decreasing availability of oxygen to the surface reaction.

Proper control of these four factors—oxygen, temperature, time, and turbulence—are necessary in order to achieve efficient combustion with a minimum of air pollutant emissions. This chapter will concentrate on the combustion fundamentals associated with theoretical air and thermochemical calculations. Gas laws will be applied in determining the volumetric flow rates of various streams in combustion processes. The effect of temperature on the reaction rates and equilibria will also be discussed in general terms. Subsequent chapters will discuss the applications of these principles to the burning or oxidation of specific combustible substances in selected combustion equipment.

Stoichiometric Combustion Air

Oxygen is necessary for combustion. The amount of oxygen required for complete combustion is known as the stoichiometric or theoretical oxygen and is determined by the nature and, of course, the quantity of the combustible material to be burned. With the exception of some exotic fuels, combustion oxygen is usually obtained from atmospheric air.

Consider a generalized fuel with a chemical formula $C_x H_y S_z O_w$ where the indices x, y, z, and w represent the relative number of atoms of carbon, hydrogen, sulfur, and oxygen respectively. Balancing the chemical reaction for the complete oxidation (combustion) of this fuel with oxygen from air gives:

$$\text{(2.1)} \quad C_xH_yS_zO_w + (x + \frac{Y}{4} + z - \frac{w}{2})\, O_2 + \frac{0.79}{0.21}\, (x + \frac{Y}{4} + z - \frac{w}{2})\, N_2 \rightarrow$$

$$\rightarrow x\, CO_2 + \frac{Y}{2} H_2O + z\, SO_2 + \frac{0.79}{0.21} (x + \frac{Y}{2} + z - \frac{w}{2})\, N_2 + Q$$

where Q represents the heat of combustion.

The above reaction assumes that:

- air consists of 21% by volume of oxygen with the remaining 79% made up of nitrogen and other inerts;
- combined oxygen in fuel is available for combustion, thus reducing air requirements;
- fuel contains no combined nitrogen, so no "fuel NO_X" is produced;
- "thermal NO_X via the nitrogen fixation is small, so that it is neglected in stoichiometric air calculations;
- sulfur in fuel is oxidized to SO_2 with negligible SO_3 formation.

Equation 2.1 relates the reactants on a molar basis. One gram-mole of a substance is the mass of that substance equal to its molecular weight in grams. A gram-mole of any substance contains Avogadro's number of molecules of that substance, i.e., there are 6.02×10^{23} molecules/g-mole. Pound-moles (lb-mole) are also in common use. Since one pound-mole is equivalent to the molecular weight of the substance in pounds, it contains 454 times as many molecules as a gram-mole.

The generalized combustion equation, Equation 2.1 can be converted to a mass basis simply by multiplying the number of moles of each substance by its respective molecular weight.

Avogadro's law states:

> Equal volumes of different gases at the same pressure and temperature contain equal numbers of molecules.

Thus it follows that the volumes of gaseous reactants in Equation 2.1 are in the same ratios as their respective numbers of moles.

The following is an example of the procedure for determining the amount of stoichiometric (or "theoretical" or "100% total") air for complete combustion of methane, CH_4, using Equation 2.1.

Referring to Equation 2.1, for CH_4: $x=1;\ y=4;\ z=w=0$.

Thus balancing the combustion equation gives:

(2.2)

$$CH_4+2O_2+2\times 3.76N_2 \rightarrow CO_2+2H_2O+7.52\ N_2$$

(2.2a)
moles or relative volumes:

$$\underbrace{1+2+7.524}_{\textit{total air}} \rightarrow \underbrace{1+2+7.52}_{\textit{flue products}}$$

Error
0.13%

(2.2b)
mass:

$$16+64+211 \rightarrow 44+36+211$$

(2.2c)
mass/ combustibles:

$$1+4+\frac{211}{16}=13.108=13.19 \rightarrow 2.75+2.25+13.19$$

Error
0.75%

The above expression gives not only the theoretical air requirements in terms of moles or volume, Equation 2.2a, and mass (2.2b, c), but it also permits the determination of the resulting combustion products which the flue needs to handle.

Attachment 2-1 (page 2-14) gives similar results for a number of combustible compounds in addition to methane. This table also contains other useful data for combustion calculations, including molecular weights, densities, specific gravities and volumes, and heats of combustion.

In the case of a pure compound, such as methane in the previous example and all substances listed in Attachment 2-1, the *x*, *y*, *z*, and *w* indices have interger or zero values in the generalized combustion equation, Equation 2.1. More often, however, one is interested in burning fuels which are mixtures of combustible substances, such as fuel oils and coal for example. In these cases the *x*, *y*, etc. indices may take on fractional values and the general chemical formula is indicative only of the relative abundance of the atomic species rather than of any exact molecular architecture. However, Equation 2.1 could still be used—even with non-integer coefficients. The indices in the chemical formula for a mixture can be obtained from its ultimate chemical analysis by dividing the percent (by weight) of composition of each of the constituent elements by their respective atomic weights. After having thus established the formula for the fuel, one could then apply Equation 2.1 to make the desired combustion calculations.

It is often easier, however, to incorporate the conversion from the ultimate analysis to the chemical formula of the fuel into a general expression which gives the amount of air required. One such expression frequently used with solid and liquid fuels is:

$$(2.3) \qquad M_{A,t} = 11.53\ C + 34.34\ (H_2 - \frac{1}{8} O_2) + 4.29\ S$$

where $M_{A,t}$ is the mass of stoichiometric air per unit mass of fuel, and C, H_2, O_2, and S now represent the weight fractions, i.e., percent/100, of carbon, hydrogen, and sulfur in the fuel, respectively. Note that the numerical coefficients in Equation 2.3 are the same as the mass (pounds) of air per mass (pounds) of combustibles for the corresponding elements in Attachment 2-1.

For mixtures of gaseous fuels it is easier to compute the amount of air required for each of the constituent compounds, e.g., methane, ethane, ethylene, etc. directly, using the constants from Attachment 2-1, and then adding them to get the total. Further, as the analyses of gaseous fuels are usually available on a volumetric basis, the volume rather than mass of stoichiometric air is of the most interest. Thus, for a unit volume of gaseous fuel, say 1 scf (standard cubic foot), the volume of theoretical air, $V_{A,t}$, also in standard cu.ft., is:

$$(2\text{-}4) \qquad V_{A,t} = 2.38\ (CO + H_2) + 9.53\ CH_4 + 16.68\ C_2H_6 + 14.29\ C_2H_4$$

$$+ 11.91\ C_2H_2 + \ldots + 7.15\ H_2S - 4.76\ O_2$$

where the molecular symbols now represent the volume fractions of the indicated components, and the numerical coefficients are again found in Attachment 2-1, but this time from the "mole per mole of combustibles or cu. ft. per cu. ft. combustibles" column. Should the gas mixture obtain other combustible substances not already included in Equation 2.4, these can be added similarly. Absence of a substance means that its volume fraction is zero and that term will drop out of Equation 2.4.

The products of complete combustion are CO_2, H_2O, SO_2, and N_2 from combustion air. The quantities of these can also be determined with the help of Attachment 2-1. For example, the mass of flue products produced per unit mass of any fuel burned is:

(2.5) $$M_{CO_2} = 3.66\ C$$

$$M_{H_2O} = 8.94\ H_2 + H_2O^*$$

$$M_{SO_2} = 2.00\ S$$

$$M_{N_2} = 8.86\ C + 26.41\ (H_2 - \frac{1}{8} O_2) + 3.29\ S + N_2^{**}$$

where the atomic and molecular symbols once again represent the weight fraction of the respective constituents in the fuel, and:

H_2O^* is the weight fraction of water in the fuel as moisture, and
N_2^{**} is the weight fraction of N_2 in the fuel as nitrogen.

Note also that any moisture in the combustion air needs to be added to the theoretical combustion products from Equation 2.5 to obtain the total flue gas stream for complete combustion with theoretical air.

Volumetric Relations for Gases and Vapors

It is often necessary to find the volume of a gas or a gas mixture at different conditions of temperature and pressure. The volume of an ideal or perfect gas has been found to be directly proportional to its absolute temperature, T, and inversely proportional to the absolute pressure, p.

(2.6) $$v^* = \frac{V}{n} = R\frac{T}{p}$$

where v^* is the molar volume, and V the total volume of n moles of the gas. The coefficient of proportionality, R, is the universal gas constant, and is identical for all ideal gases. The numerical value of R does, however, vary depending on the units used for other quantities in the ideal gas law, Equation 2.6. Values of R for some more frequently used sets of units are listed in Attachment 2.2 (page 2-15).

According to Equation 2.6, one mole of any ideal gas occupies the same volume at the same pressure and temperature. Thus a comparison of volumes at identical, often standardized, conditions is useful as an indicator of the relative numbers of molecules or moles involved. Molar volumes of ideal gases at several such "standard" conditions are given in Attachment 2.3 (page 2-16). The ideal gas law, Equation 2.6, is quite adequate for the gas phase pressure-volume-temperature relations in most combustion processes. Significant deviations from such ideal behavior begin to appear only at pressures much higher than are encountered in most combustion installations.

Since most combustion processes take place at essentially constant pressure, normally close to one atmosphere, the volume of gases at some other temperatures can be calculated using Charles' law:

$$V_1 = V_0 \left[\frac{T_1}{T_0} \right] \tag{2.7}$$

Note that one needs to use absolute temperatures, either degrees Rankine (°F + 460) or Kelvin (°C + 273.15) in Equation 2.7. Charles' law is merely a special application of the ideal gas law by taking the ratio of Equation 2.6 written at conditions 0 and 1 for a fixed amount of gas $(n_0 = n_1)$ at constant pressure $(p_0 = p_1)$.

Boyle's law, Equation 2.8, relates the volume to pressure at constant temperature $(T_0 = T_1)$ and amount of gas $(n_0 = n_1)$, and can also be obtained from Equation 2.6.

$$V_1 = V_0 \left[\frac{p_0}{p_1} \right] \tag{2.8}$$

Charles' and Boyle's laws are more convenient to use than the ideal gas law if there is only one variable affecting a change in volume, i.e., temperature or pressure, respectively.

Partial pressure of the i-th component, p_i, of a mixture is the pressure exerted by that component if it were to occupy alone the same volume as the mixture at the same temperature. Dalton's law states that the total pressure, p, exerted by a mixture is the sum of the partial pressures of each of its components:

$$p = \Sigma p_i = p_A + p_B + p_C + \cdots\cdots \tag{2.9}$$

where

$$p_i = \left[\frac{n_i}{n} \right] p$$

Flammability Characteristics of Gases and Vapors

A homogeneous mixture of a combustible gas and air is said to be flammable if it can propogate a flame. Flammability is limited to a finite range of compositions, even when the mixture is subjected to an ignition source or to elevated temperatures. This limit at the more dilute mixture of combustibles is known as the lower flammability or explosive limit (LEL), while the limit at the more concentrated (combustible-rich limit) end of the flammable range is the upper flammability or explosive limit (UEL).

At concentrations below LEL the localized heat release rate of the oxidation reaction at the ignition source is lower than the rate at which heat is dissipated to the surroundings, and therefore it is not possible to maintain high enough temperature which is required for flame propogation or sustained combustion. Above the upper flammability limit, there is less than the necessary amount of oxygen, with the result that the flame does not propogate due to the local depletion of oxygen, thus causing the temperature, and hence the oxidation rate, to drop below the levels required for sustained combustion.

The rate of flame propogation in combustible mixtures covers a wide range as it depends on a number of factors including the nature of the combustible substance, mixture composition, temperature, and pressure. For a given substance the flame propogation rate is maximum at or near the stoichiometric mixture composition, and drops off to zero at the upper and lower explosive limits.

Attachment 2-4 (page 2-17) is typical of the effect of temperature on the limits of flammability. Here T_L is defined as the lowest temperature at which a liquid combustible has vapor pressure high enough to produce a vapor-air mixture within the flammability range (at LEL). The autoignition temperature (AIT) on the other hand, is the lowest temperature at which a uniformly heated mixture will ignite spontaneously. These quantities are summarized for selected combustible substances in Attachment 2-5 (page 2-18). Good sources of such data for a large number of different gases and vapors are Bureau of Mines Bulletins 503 and 627 (2, 3).

Thermochemical Relations

Combustion reaction, with its release of heat and light, is referred to as an exothermic reaction. Energy, which is released as the result of rearranging chemical bonds, can be utilized for power generation, space heating, drying, or for air pollution abatement, just to mention a few applications. Thermochemical calculations, which are the subjects of the next several secctions of this chapter, are concerned with the heat effects associated with combustion. These calculations permit determination of the energy released by burning a specific fuel. Only a part of this heat will be available for useful work, however.

Each combustion installation has heat losses, some of which can be controlled to a certain extent, and others over which there is little or no control. The avoidable heat losses are those which can be minimized by good design and careful operation. They will be discussed in subsequent chapters. The efficiency of a combustion installation reflects how well the designer succeeded in this respect. The percent efficiency is defined as 100 minus the sum of all losses, expressed as percent of the energy input from the fuel.

In order to make efficiency as well as other thermochemical calculations, one needs to be able to determine the fuel heating values, heat contents on entering and leaving streams, and any other heat losses. Since rather specialized terminology is involved, a definition of terms is in order to avoid confusion and ambiguities later.

Heat of Combustion--Heat energy evolved from the union of a combustible substance with oxygen to form CO_2, H_2O (and SO_2) as the end products, with both the reactants starting, and the products ending at the same conditions, usually 25°C and 1 atm.

Gross or Higher Heating Value—HV_G or *HHV*—The quantity of heat evolved as determined by a calorimeter where the combustion products are cooled to 60°F and all water vapor condensed to liquid. Usually expressed in terms of Btu/lb or Btu/scf.

Net or Lower Heating Value—HV_N or *LHV*—Similar to the higher heating value except that the water produced by the combustion is not condensed but retained as vapor at 60°F. Expressed in the same units as the gross heating value.

Enthalpy or Heat Content—Total heat content, expressed in Btu/lb, above a standard reference condition.

Sensible Heat—Heat, the addition or removal of which results in a change of temperature.

Latent Heat—Heat effect associated with a change of phase, e.g., from liquid to vapor (vaporization), or from liquid to solid (fusion), etc., without a change in temperature. Expressed usually as Btu/lb.

Available Heat—The quantity of heat available for intended (useful) purposes. The difference between the gross heat input to a combustion chamber and all the losses.

According to a heat balance, energy outflow from a system and accumulation within the system equals the energy input to the system. For steady-state operations the accumulation term is zero. Therefore:

(2.10) *Heat In (sensible + HHV) = Heat Out (sensible + latent + available)*

Attachment 2-6 (page 2-19) illustrates the various quantities in the heat balance and their interrelations. The length of each bar (Parts 2-6.b, d) represent the heat content of the respective stream or streams. Part 2-6.c of Attachment 2-6 gives the same information as Parts 2-6.b and 2-6.d, but recognizes in addition that the heat contents (enthalpies) are functions of temperature. The sensible heat content of fuel and air, above the 60°F enthalpy reference level, needs to be added to the gross heating value on the input side. The amount added will depend, of course, on the temperature of these streams and could in fact be negative, if any of them enter at temperatures below 60°F.

Flue losses are made up of sensible and latent heat contributions and are also dependent on the temperature. The higher the flue gas temperature, the higher these losses are, and the less heat remains for useful work. Conversely, the extraction of heat from the system, presumably for some useful purpose, decreases the stack gas heat content and improves the heat utilization efficiency of the operation. Stack gas temperature should not be allowed, however, to drop below the level where condensation will appear (to avoid corrosion problems).

An estimate of the adiabatic flame temperature is obtained from Attachment 2-6.c by extending the combustion products temperature vs. enthalpy curve until no heat is extracted (Available Heat = 0). The actual adiabatic temperature will not be as high, though, since (a) combustion is not instantaneous and some heat losses to the surroundings are likely to occur, and (b) at temperatures above about 3,000°F some CO_2 and H_2O will begin to dissociate absorbing some heat. Note that preheating fuel and combustion air permits the generation of higher temperatures in the combustion chamber or higher amounts of heat available for useful purposes at the same exit gas temperature levels.

Further, some of the hottest flames available are obtained by the use of oxygen instead of air. The oxy-acetylene torch can reach 5,600°F, oxy-hydrogen torch 6,800°F, and oxy-atomic hydrogen torch about 10,000°F, all because of the absence of flue gas nitrogen heat losses.

Attachment 2-6 is rather idealized and should be used only in a qualitative sense. For example, no radiation or conduction (through furnace walls) is considered. The boundary between the sensible and latent heat contributions cannot be segregated as sharply as indicated—condensation will occur over a range of temperatures. Thus, in a real system the dashed curve may be more representative of the true situation. Also, the increasing heat contents are not always linear with temperature as shown. The reciprocal of the slope of these lines is proportional to the specific heats which are known to be functions of temperature.

Let us now compute the flue gas losses by determining the heat content of exiting combustion products. Consider a general case where the stack gases are made up of n components, the quantities of each, $\dot{m}_i$, having been determined earlier in this chapter

The total mass flow rate of the stack gases $\dot{m}_{tot}$ (lb/hr) is:

$$\dot{m}_{tot} = \dot{m}_1 + \dot{m}_2 + \ldots + \dot{m}_1 + \ldots + \dot{m}_n = \sum_{i=1}^{n} \dot{m}_i \tag{2.11}$$

Assuming no latent heat effects (no phase changes), the enthalpy of each component h_i (Btu/lb) at temperature T_2 is:

$$h_i = C_{p,i}\,(T_2 - T_0) \tag{2.12}$$

where $C_{p,i}$ = *specific heat of i-th component, Btu/lb°F and*

T_0 = *reference temperature for enthalpy* ($h = 0$ *at* $T = T_0$), °F.

Enthalpies at various temperatures can be calculated by Equation 2.12 if the specific heat data are available, or they could be obtained from Attachment 2-7, which gives the enthalpies for a number of gases of interest in combustion calculations. Heat contents at intermediate temperatures can be obtained by linear interpolation.

Enthalpy of a mixture, h_{mix} (Btu/lb), at T_2 is then:

$$h_{mix} = \sum_{i=1}^{n} x_i\,h_i = \sum_{i=1}^{n} x_i\,C_{p,i}(T_2 - T_0) \tag{2.13}$$

where x_i is the weight fraction of component i in the mixture, i.e., $x_i = m_i/m_{tot}$ and $\Sigma\, x_i = 1.0$.

Any latent heat effects need to be accounted for by adding terms such as ($m_i\,\lambda_i$), is the latent heat of vaporization (condensation) of the i-th component.

The total flue loss, $q_{flue\ loss}$ (Btu/hr), is then the sum of all the enthalpies of the stack gas components:

$$q_{flue\ loss} = \dot{m}_{tot}\ h_{mix} = \Sigma\ \dot{m}_i\ h_i = (T_2 - T_0)\ \Sigma\ (\dot{m}_i\ C_{p,i}) \tag{2.14}$$

The sensible heat input by air and fuel can be calculated by an equation analogous to Equation 2.14 and is:

$$q_{fuel,\ air} = (T_1 - T_0)\ \Sigma\ \dot{m}_j\ C_{p,j} \tag{2.15}$$

where T_1 is the fuel and air inlet temperature, and the subscript j represents input components.

With the higher (gross) heating value of the fuel, Q_H (Btu/lb fuel), the available heat, Q_A (Btu/hr), from this installation will be:

$$Q_A = \dot{m}_{fuel}\, Q_H + q_{fuel,\, air} - q_{flue\ losses} \tag{2.16}$$

Note again that the above has not included any radiation or conduction losses. Should these occur, they need to be subtracted from the right side of Equation 2.16.

These calculations have already been performed for different types of fuels, and the results presented in tabular or graphical form to facilitate the design or the evaluation of a combustion process. Curves in Attachment 2-8 show the available heat (if the hydrogen to carbon ratio in the fuel is known) for a complete combustion of various fuels with stoichiometric air and fuel input at 60°F. These curves serve as a generalized comparison for all hydrocarbon fuels.

Curves in Attachment 2-9 would be preferred should data for specific fuels be available. Attachment 2-10 is still another generalization for hydrocarbon fuels giving the available heat as a percent of the gross heating value and various amounts of excess combustion air. Note that this chart is only approximate since it is based on the assumption that the combustion air required per gross Btu heating value is the same for all fuels.

Attachment 2-11 relates the various combustion losses to the air-to-fuel ratio. With perfect mixing, one would expect a minimum in total losses at the stoichiometrically correct air/fuel ratio. As a result of a less than perfect mixing, however, the minimum total loss occurs at higher air/fuel ratios (excess air). The exact location of this minimum depends not only on the degree of mixing of the fuel and combustion air, but also on the characteristic burning rate of the particular fuel. Recommended excess air quantities for an optimal combustion efficiency from the heat utilization point of view will be discussed under the respective fuels burning chapters.

Reaction Equilibrium and Kinetics

The following is a qualitative discussion of the chemical reaction equilibrium and kinetics in an attempt to clarify the roles which concentrations and temperature play in combustion processes. Much has been written on the subject with most of the more recent work by chemists at a level too sophisticated for the purpose here. There are, however, quite readable discussions available, among them a book by J.B. Edwards (5).

Chemical reactions are seldom as simple and complete as was implied by the general combustion reaction Equation 2.1. All reactions are considered to be reversible to some extent. How far a reaction proceeds depends on the relative rates of the forward and reverse reactions. Consider a reaction where reactants A and B form products C and D:

$$A + B \rightleftharpoons C + D \tag{2.17}$$

From the law of mass action, the rates of reactions are proportional to the concentrations of reactants. Hence the forward rate, r_f, is:

$$r_f = k_f [A] [B] \tag{2.18}$$

and the reverse rate:

$$r_r = k_r [C] [D] \tag{2.19}$$

where the *k's* represent the reaction velocity constants, and the square brackets the concentration of the respective species.

At equilibrium the forward and reverse rate are necessarily equal. Thus:

$$k_f [A] [B] = k_r [C] [D] \tag{2.20}$$

It is now convenient to define an equilibrium constant K:

$$K = \frac{k_f}{k_r} = \frac{[C] [D]}{[A] [B]} \tag{2.21}$$

The equilibrium constant, K, is a function of temperature through the temperature effect on the reaction velocity constants k_f and k_r. Note that if it were desired to reduce the concentration of one of the reactants, say reactant A for example, this could be accomplished by increasing the concentration of B. This is exactly the rationale for using excess air to assure complete combustion of the fuel.

It is common knowledge that some reactions proceed faster than others. The reaction rates depend on the chemical bonding in the materials. Enough energy must be supplied to break the chemical bonds in the fuel and in the molecular oxygen before new bonds can be formed. It is convenient to think of this energy as elevating the reactants to a new higher energy state, called the transition state, where an activated but unstable complex is formed from the reactants. This complex can break up into new products or go back to the initial reactants. Such a model of a chemical reaction is illustrated in Attachment 2-12. The energy necessary to raise the reactant molecules to the transition state is called the activation energy, ΔE.

Molecules in any substance are distributed over a spectrum of energies as indicated on the left side of Attachment 2-12. There are relatively few molecules at very high and very low energies with the bulk of them at some intermediate energy state. The area under the distribution curve represents the total number of molecules in the system. The energy spectrum is a function of temperature, and shifts to a higher energy level as temperature increases (e.g., dashed curve at T_2).

Only these molecules which are in energy states equal to or higher than the transition state will be able to form the activated complex and eventually the products. The fraction of molecules which possesses this requisite activation energy is higher at elevated temperatures, as is apparent by the larger shaded area under the energy distribution curve at T_2 in comparison with that at T_1. Therefore, at higher temperatures one can expect a higher reaction rate. This temperature effect on the reaction rate can be represented by an Arrhenius-type relation, as shown in Attachment 2-13. The temperature effect is exponential and gives a straight line on a semilog plot of k vs. the reciprocal of the absolute temperature.

The presence of a catalyst increases the reaction rate, but not the total amount of products obtained, nor the equilibrium concentrations. Many surface-type catalysts introduce adsorption/desorption steps into the overall reaction sequence, as shown in Attachment 2-14. The net effect of these steps is an apparent lowering of the effective activation energy. This makes it possible for a larger fraction of reactant molecules to reach the transition state with the result that the reaction rate will increase. The bottom half of Attachment 2-14 illustrates how a catalyst increases the reaction rate through an increased k-value at constant temperature, or that the same rate could be obtained with catalyst at a higher l/T (or lower absolute temperature, T).

Practical applications of the above are found in the catalytic incineration of combustible gases and vapors discussed in Chapter 13. Temperatures and residence times required for catalytic oxidation are much lower (see page 13-29) than those required by thermal afterburners (see page 13-17).

Summation

Insufficient air will result in incomplete combustion with emissions of pollutants such as carbon monoxide, solid carbon particulates in the form of smoke or soot, and unburned and/or partially oxidized hydrocarbons.

Burning carbon with insufficient oxygen can produce CO:

$$C + \frac{1}{2}O_2 \rightarrow CO \tag{2.22}$$

With additional oxygen the carbon monoxide can be converted to CO_2:

$$CO + \frac{1}{2}O_2 \rightarrow CO_2 \tag{2.23}$$

Even gaseous fuels, such as methane, could produce pollutants when burned with too little oxygen:

$$CH_4 + O_2 \rightarrow C_{(solid)} + 2\,H_2O \tag{2.24}$$

The solid carbon particles can agglomerate resulting in smoke and soot. Somewhat more oxygen, but still less than theoretical, could lead to carbon monoxide formation by the following reaction:

$$CH_4 + \frac{3}{2} O_2 \rightarrow CO + 2 H_2O \qquad (2.25)$$

Reactions similar to those represented by Equations 2.22 and 2.25 can occur in the presence of adequate air if: (a) the oxygen is not readily available for the burning process, as a result of inadequate mixing or turbulence, (b) the flame is chilled too rapidly, and/or (c) the residence time is too short. These "3 *T's* of Combustion" are all interrelated and need to be considered carefully in order to achieve efficient combustion with a minimum of pollutant emissions.

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4. *North American Combustion Handbook*, North American Manufacturing Company, Cleveland, Ohio, 1st Edition (1952), 2nd Edition (1978).
5. Edwards, J.B., *Combustion: The Formation and Emission of Trace Species*, Ann Arbor Science Publishers, Ann Arbor, Michigan (1974).

Attachment 2-1. Combustion constants

No.	Substance	Formula	Molecular Weight	Lb per Cu Ft	Cu Ft per Lb	Sp Gr Air = 1.0000	Heat of Combustion				For 100% Total Air Moles per mole of Combustible or Cu Ft per Cu Ft of Combustible						For 100% Total Air Lb per Lb of Combustible					
							Btu per Cu Ft		Btu per Lb		Required for Combustion			Flue Products			Required for Combustion			Flue Products		
							Gross (High)	Net (Low)	Gross (High)	Net (Low)	O_2	N_2	Air	CO_2	H_2O	N_2	O_2	N_2	Air	CO_2	H_2O	N_2
1	Carbon*	C	12.01	–	–	–	–	–	14,093	14,093	1.0	3.76	4.76	1.0	–	3.76	2.66	8.86	11.53	3.66	–	8.86
2	Hydrogen	H_2	2.016	0.0053	187.723	0.0696	325	275	61,095	51,623	0.5	1.88	2.38	–	1.0	1.88	7.94	26.41	34.34	–	8.94	26.41
3	Oxygen	O_2	32.00	0.0846	11.819	1.1053	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
4	Nitrogen (atm)	N_2	28.01	0.0744	13.443	0.9718	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
5	Carbon monoxide	CO	28.01	0.0740	13.506	0.9672	321	321	4,347	4,347	0.5	1.88	2.38	1.0	–	1.88	0.57	1.90	2.47	1.57	–	1.90
6	Carbon dioxide	CO_2	44.01	0.1170	8.548	1.5282	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Paraffin series																					
7	Methane	CH_4	16.04	0.0425	23.552	0.5543	1012	911	23,875	21,495	2.0	7.53	9.53	1.0	2.0	7.53	3.99	13.28	17.27	2.74	2.25	13.28
8	Ethane	C_2H_6	30.07	0.0803	12.455	1.0488	1773	1622	22,323	20,418	3.5	13.18	16.68	2.0	3.0	13.18	3.73	12.39	16.12	2.93	1.80	12.39
9	Propane	C_3H_8	44.09	0.1196	8.365	1.5617	2524	2322	21,669	19,937	5.0	18.82	23.82	3.0	4.0	18.82	3.63	12.07	15.70	2.99	1.63	12.07
10	n-Butane	C_4H_{10}	58.12	0.1582	6.321	2.0665	3271	3018	21,321	19,678	6.5	24.47	30.97	4.0	5.0	24.47	3.58	11.91	15.49	3.03	1.55	11.91
11	Isobutane	C_4H_{10}	58.12	0.1582	6.321	2.0665	3261	3009	21,271	19,628	6.5	24.47	30.97	4.0	5.0	24.47	3.58	11.91	15.49	3.03	1.55	11.91
12	n-Pentane	C_5H_{12}	72.15	0.1904	5.252	2.4872	4020	3717	21,095	19,507	8.0	30.11	38.11	5.0	6.0	30.11	3.55	11.81	15.35	3.05	1.50	11.81
13	Isopentane	C_5H_{12}	72.15	0.1904	5.252	2.4872	4011	3708	21,047	19,459	8.0	30.11	38.11	5.0	6.0	30.11	3.55	11.81	15.35	3.05	1.50	11.81
14	Neopentane	C_5H_{12}	72.15	0.1904	5.252	2.4872	3994	3692	20,978	19,390	8.0	30.11	38.11	5.0	6.0	30.11	3.55	11.81	15.35	3.05	1.50	11.81
15	n-Hexane	C_6H_{14}	86.17	0.2274	4.398	2.9704	4768	4415	20,966	19,415	9.5	35.76	45.26	6.0	7.0	35.76	3.53	11.74	15.27	3.06	1.46	11.74
	Olefin series																					
16	Ethylene	C_2H_4	28.05	0.0742	13.475	0.9740	1604	1503	21,636	20,275	3.0	11.29	14.29	2.0	2.0	11.29	3.42	11.39	14.81	3.14	1.29	11.39
17	Propylene	C_3H_6	42.08	0.1110	9.007	1.4504	2340	2188	21,048	19,687	4.5	16.94	21.44	3.0	3.0	16.94	3.42	11.39	14.81	3.14	1.29	11.39
18	n-Butene	C_4H_8	56.10	0.1480	6.756	1.9336	3084	2885	20,854	19,493	6.0	22.59	28.59	4.0	4.0	22.59	3.42	11.39	14.81	3.14	1.29	11.39
19	Isobutene	C_4H_8	56.10	0.1480	6.756	1.9336	3069	2868	20,737	19,376	6.0	22.59	28.59	4.0	4.0	22.59	3.42	11.39	14.81	3.14	1.29	11.39
20	n-Pentene	C_5H_{10}	70.13	0.1852	5.400	2.4190	3837	3585	20,720	19,359	7.5	28.23	35.73	5.0	5.0	28.23	3.42	11.39	14.81	3.14	1.29	11.39
	Aromatic series																					
21	Benzene	C_6H_6	78.11	0.2060	4.852	2.6920	3752	3601	18,184	17,451	7.5	28.23	35.73	6.0	3.0	28.23	3.07	10.22	13.30	3.38	0.69	10.22
22	Toluene	C_7H_8	92.13	0.2431	4.113	3.1760	4486	4285	18,501	17,672	9.0	33.88	42.88	7.0	4.0	33.88	3.13	10.40	13.53	3.34	0.78	10.40
23	Xylene	C_8H_{10}	106.16	0.2803	3.567	3.6618	5230	4980	18,650	17,760	10.5	39.52	50.02	8.0	5.0	39.52	3.17	10.53	13.70	3.32	0.85	10.53
	Miscellaneous gases																					
24	Acetylene	C_2H_2	26.04	0.0697	14.344	0.9107	1477	1426	21,502	20,769	2.5	9.41	11.91	2.0	1.0	9.41	3.07	10.22	13.30	3.38	0.69	10.22
25	Naphthalene	$C_{10}H_8$	128.16	0.3384	2.955	4.4208	5854	5654	17,303	16,708	12.0	45.17	57.17	10.0	4.0	45.17	3.00	9.97	12.96	3.43	0.56	9.97
26	Methyl alcohol	CH_3OH	32.04	0.0846	11.820	1.1052	868	767	10,258	9,066	1.5	5.65	7.15	1.0	2.0	5.65	1.50	4.98	6.48	1.37	1.13	4.98
27	Ethyl alcohol	C_2H_5OH	46.07	0.1216	8.221	1.5890	1600	1449	13,161	11,917	3.0	11.29	14.29	2.0	3.0	11.29	2.08	6.93	9.02	1.92	1.17	6.93
28	Ammonia	NH_3	17.03	0.0456	21.914	0.5961	441	364	9,667	7,985	0.75	2.82	3.57	–	1.5	3.32	1.41	4.69	6.10	–	1.59	5.51
														SO_2						SO_2		
29	Sulfur*	S	32.06	–	–	–	–	–	3,980	3,980	1.0	3.76	4.76	1.0	–	3.76	1.00	3.29	4.29	2.00	–	3.29
30	Hydrogen sulfide	H_2S	34.08	0.0911	10.979	1.1898	646	595	7,097	6,537	1.5	5.65	7.15	1.0	1.0	5.65	1.41	4.69	6.10	1.88	0.53	4.69
31	Sulfur dioxide	SO_2	64.06	0.1733	5.770	2.2640	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
32	Water vapor	H_2O	18.02	0.0476	21.017	0.6215	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
33	Air	–	–	0.0766	13.063	1.0000	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–

*Carbon and sulfur are considered as gases for molal calculations only.

All gas volumes corrected to 60 F and 30 in. Hg dry.

Note: This table is included by courtesy of the American Gas Association and the Industrial Press. The format and data are taken principally from "Fuel Flue Gases," 1941 Edition, American Gas Association, with modifications, especially in the four columns labeled "Heat of Combustion," using data from "Gas Engineers Handbook, The Industrial Press, 1965."

Attachment 2-2. Ideal (perfect) gas law

$$\frac{pv^*}{T} = R$$

where

p = absolute pressure
v^* = molal volume
T = absolute temperature
R = universal gas constant

Selected values of R:

$$R = 1545.33 \frac{ft-lb_f}{lb-mole\ °R}$$

$$10.73 \frac{psia-ft^3}{lb-mole\ °R}$$

$$0.7302 \frac{atm-ft^3}{lb-mole\ °R}$$

$$1.987 \frac{cal}{g-mole\ °K}$$

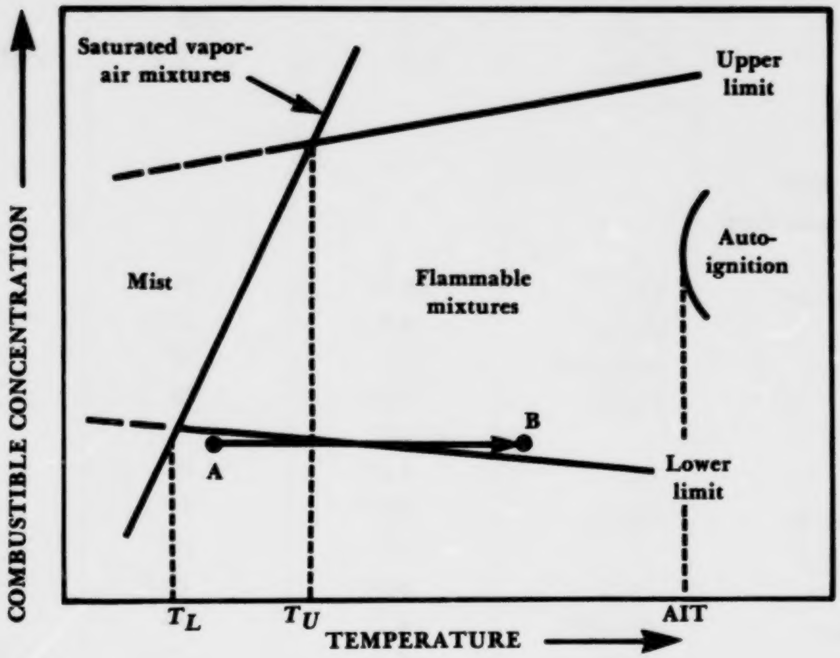
$$82.06 \frac{atm-cm^3}{g-mole\ °K}$$

$$8.315 \frac{Pa-m^3}{kg-mole\ °K}$$

Attachment 2-3. Molar volumes of ideal gases at standard conditions

Standards	Universal Scientific	Natural Gas Industry
Temperature	0°C → 273.00 K	60°F (520 R)
Pressure	1 atm → 1.013×10^5 Pa	30 in. Hg
Molar Volume	22.4 litre/g – mole	
	22.4 m^3/kg mole	
	359 ft^3/lb – mole	379 ft^3/lb – *mole*

Attachment 2-4. Temperature effect on limits of flammability in air[3]


Saturated vapor-air mixtures
Upper limit
Mist
Flammable mixtures
Auto-ignition
B
A
Lower limit
COMBUSTIBLE CONCENTRATION
T_L
T_U
AIT
TEMPERATURE

Notes:

1. The flammable region to the left of the saturated vapor-air mixture curve contains droplets of the liquid combustible (mist) suspended in a vapor-air mixture.
2. A non-flammable mixture (at Point A) may become flammable if its temperature is elevated sufficiently (to Point B) by a localized energy source.

Attachment 2-5. Limits of flammability,[a] lower temperature limits (T_L), and autoignition temperatures (AIT) for selected substances[3]

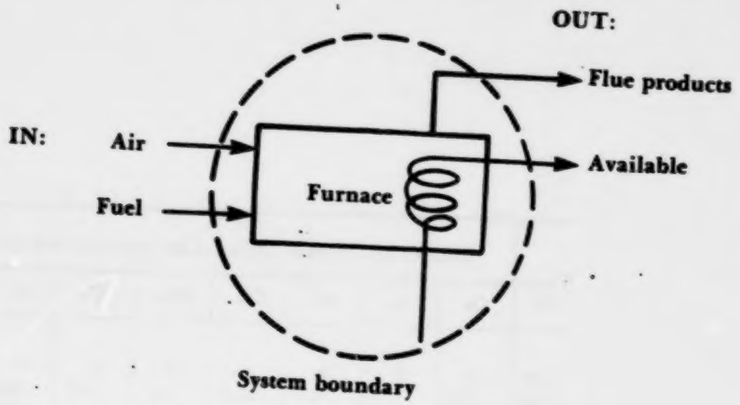
Combustion	Formula	$LEL_{25°C}$ (vol %)	$UEL_{25°C}$ (vol %)	T_L (°C)	AIT (°C)
Acetylene	C_2H_2	2.5	100	–	305
n-Butane	C_4H_{10}	1.8	8.4	−72	405
Carbon, Fixed	C				
Charcoal					340
Bituminous Coal					400
Semibituminous Coal					465
Anthracite					450-600
Carbon Monoxide	CO	12.5	74		
Ethane	C_2H_6	3.0	12.4	−130	515
Ethyl Alcohol	C_2H_5OH	3.3	19		365
Ethylene	C_2H_4	2.7	36		490
Gasoline		1.2	7.1		270-440
Hydrogen	H_2	4.0	75		400
Hydrogen Sulfide	H_2S	4.0	44		
Jet Fuel (JP-4)		1.3	8		240
Methane	CH_4	5.0	15.0	−187	540
Methyl Alcohol	CH_3OH	6.7	36		385
Propane	C_3H_8	2.1	9.5	−102	450
Sulfur	S	2.0		247	

---

[a] Flammability is for mixtures of combustibles in air at standard pressure and temperature.

Attachment 2-6. Furnace heat balance relations

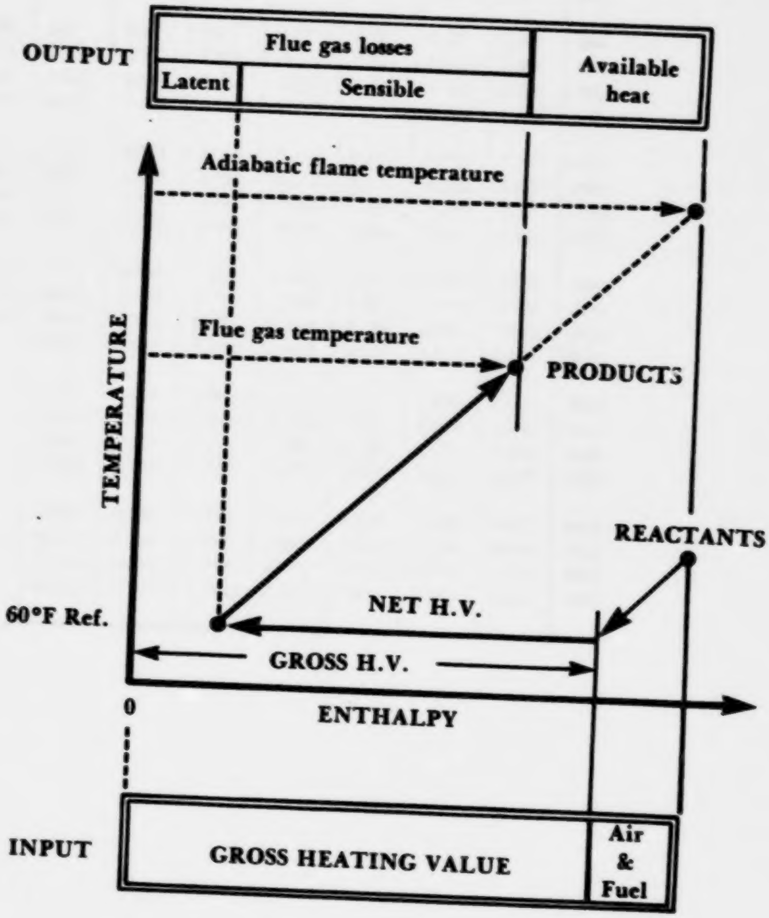
Part 2-6.a


OUT:
Flue products
IN:
Air
Available
Fuel
Furnace
System boundary

Part 2-6.b

Part 2-6.c

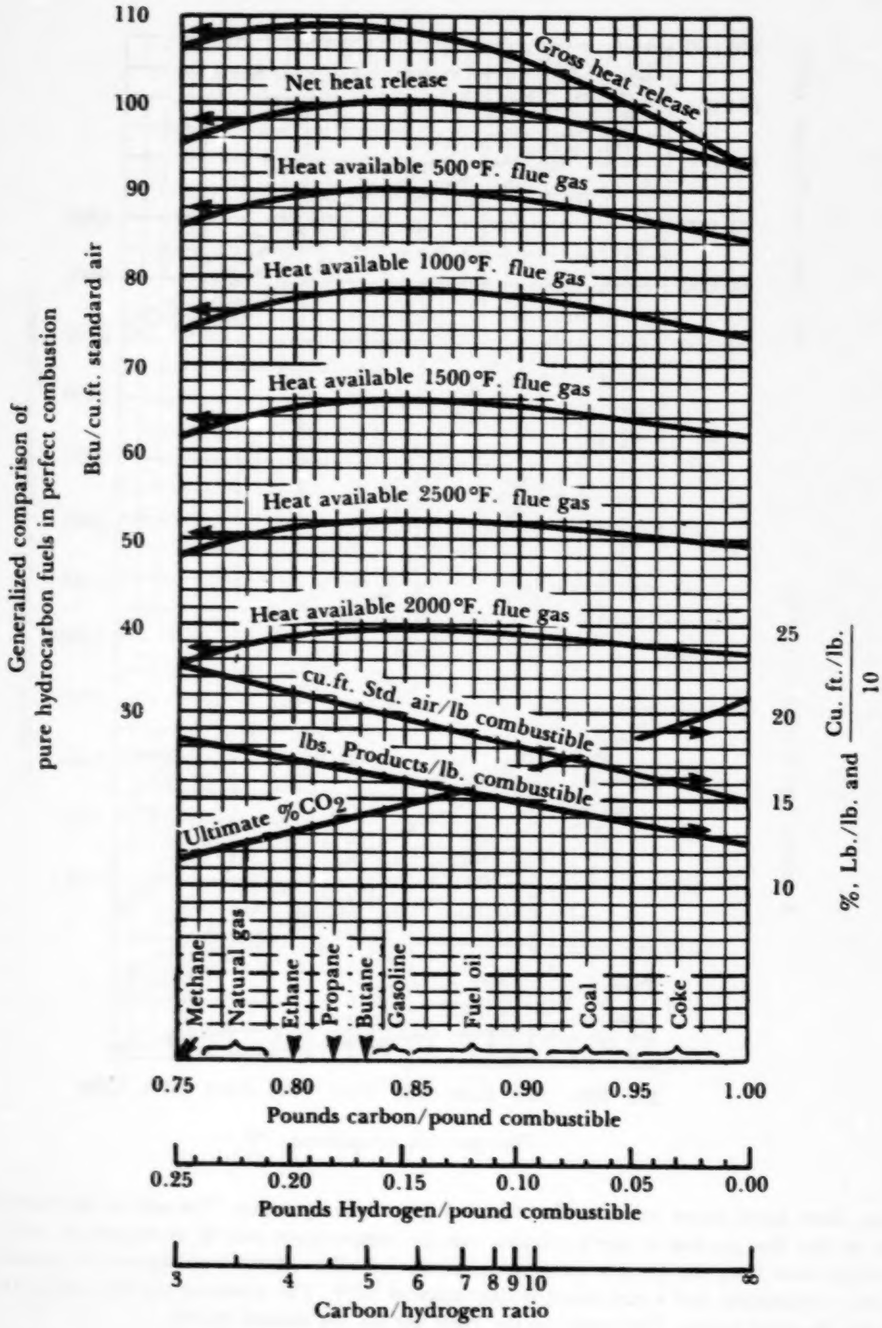
Part 2-6.d


OUTPUT
Flue gas losses
Latent
Sensible
Available heat
Adiabatic flame temperature
TEMPERATURE
Flue gas temperature
PRODUCTS
REACTANTS
NET H.V.
60°F Ref.
GROSS H.V.
0
ENTHALPY
INPUT
GROSS HEATING VALUE
Air & Fuel

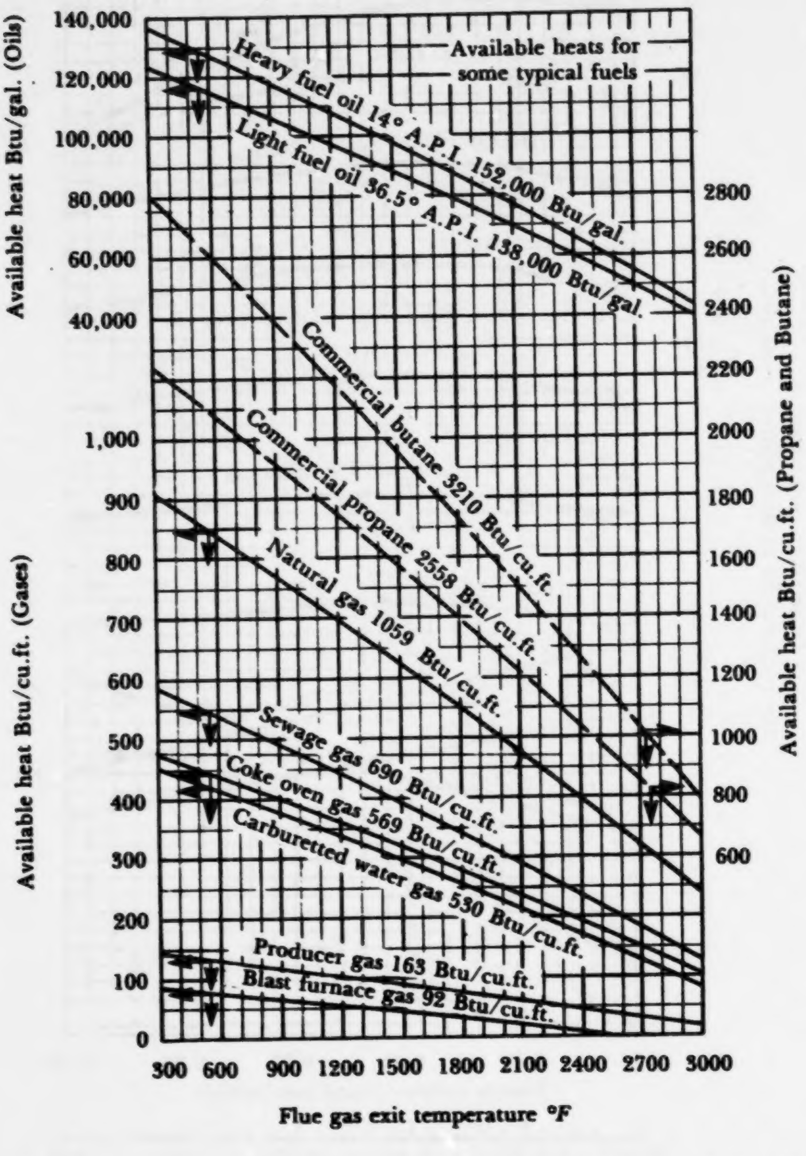
Attachment 2-7. Heat contents of various gases and water vapor [4]

Temp °F	Relative heat content (h) in Btu per pound (at atmospheric pressure)								
	O_2	N_2	Air	CO	CO_2	SO_2	H_2	CH_4	H_2O
60	0	0	0	0	0	0	0	0	0
100	8.8	9.9	9.6	10.0	8.0	5.9	137	21.0	...
200	30.9	34.8	33.6	34.9	29.3	21.4	484	76.1	...
300	53.3	59.9	57.7	59.9	52.0	37.5	832	136.4	1165
400	76.2	85.0	81.8	85.0	75.3	54.4	1182	202.1	1212
500	99.4	110.3	106.0	110.6	99.8	71.8	1532	272.6	1259
600	123.1	136.1	130.2	136.3	125.1	89.8	1882	347.8	1307
700	147.2	161.7	154.5	162.4	149.6	108.2	2233	427.4	1355
800	171.7	187.7	178.9	188.7	177.8	127.0	2584	511.2	1404
900	196.6	213.9	203.4	215.6	205.6	146.1	2935	599.2	1454
1000	221.7	240.7	235.0	242.7	233.6	165.5	3291	691.1	1505
1200	272.5	294.7	288.5	297.8	290.9	205.1	4007	886.2	1609
1400	324.3	350.8	343.0	354.3	349.7	245.4	4729	1094.1	1717
1600	377.3	407.3	398.0	407.5	416.3	286.4	5460	1313.0	1829
1800	430.7	465.0	455.0	465.3	470.9	327.8	6198	1542.6	...
2000	484.0	523.8	513.0	523.8	532.8	369.1	6952	...	...
2200	539.3	583.2	570.7	583.3	596.1	411.1	7717	...	...
2400	594.4	642.3	628.5	643.0	659.2	452.7	8490	...	...
2600	649.0	702.8	687.3	703.2	723.2	495.2	9272	...	...
2800	702.8	763.1	746.6	771.3	787.4	557.5	10060	...	...
3000	758.6	824.1	806.3	832.6	852.0	580.0	10870	...	...
3200	816.4	885.8	866.0	894.0	916.7	622.5	11680	...	...
3400	873.4	947.6	925.9	956.0	981.6	665.0	12510	...	...
3600	931.0	1010.3	986.1	1018.3	1047.3	707.5	13330	...	...

Attachment 2-8. Comparison of pure hydrocarbon fuels in perfect combustion 4

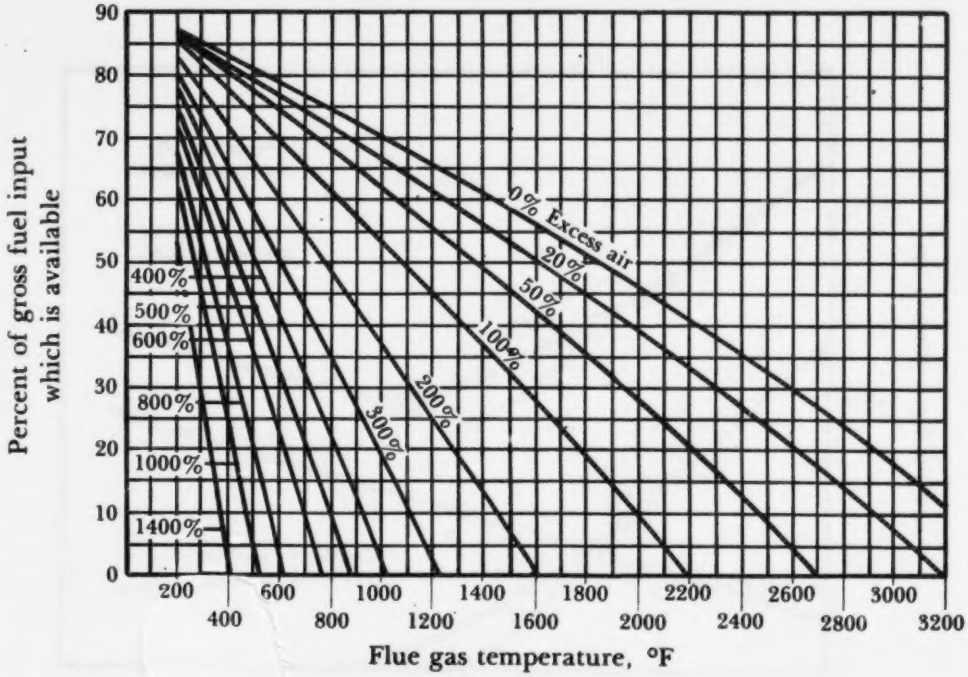


Attachment 2-9, Available heats for some typical fuels [4]



Note: Fuels listed above are identified by their gross heating values. The sum of the moisture loss and the dry flue gas loss at any particular exit gas temperature may be evaluated by subtracting the available heat from the gross heating value. Note that all available heat figures are based upon perfect combustion and a fuel input temperature of 60°F. The scales on the left side of this chart are for the solid curves. The scales on the right are for the dashed curves.

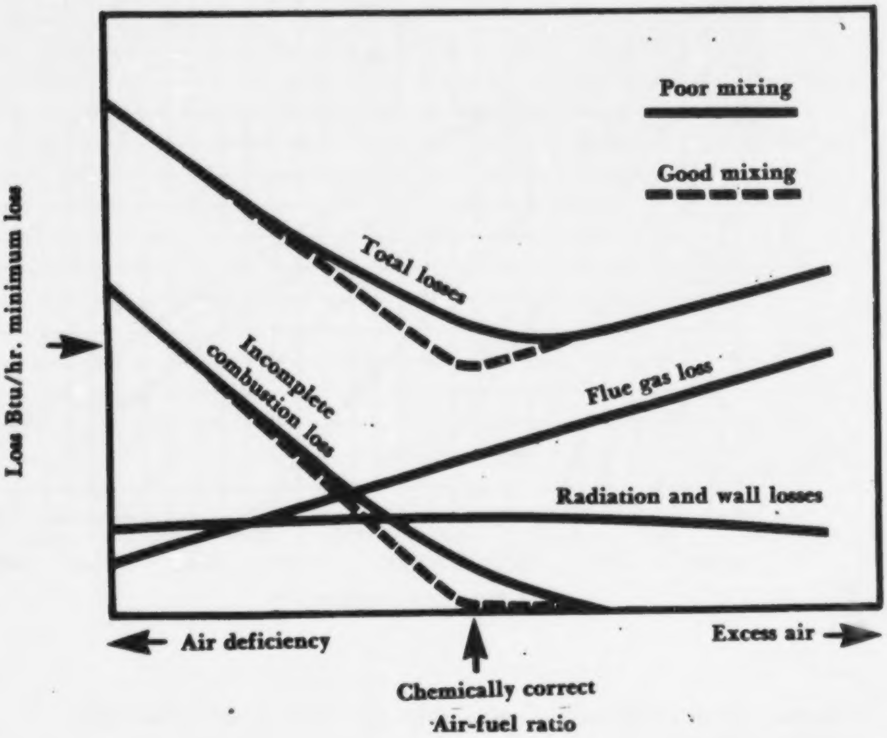
Attachment 2-10. Generalized available heat chart for all fuels at various flue gas temperatures and various excess combustion air[4]
(Refer to 60°F)



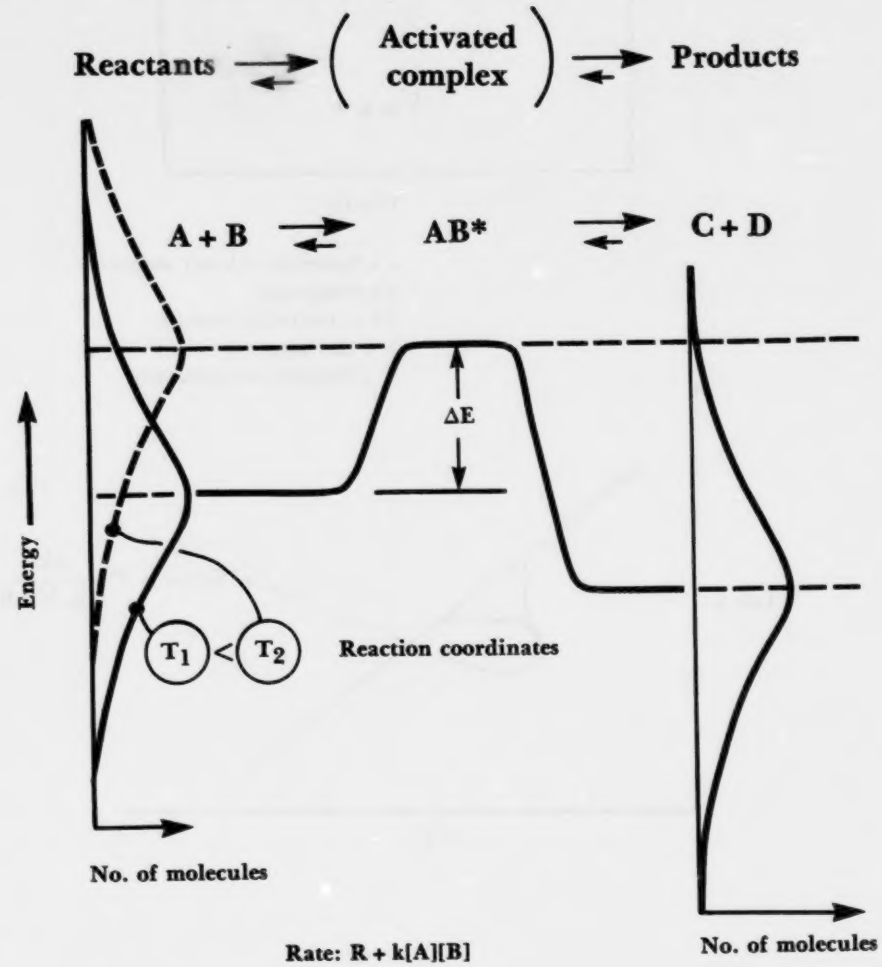
This chart is only applicable to cases in which there is no unburned fuel in the products of combustion.

The average temperature of the hot mixture just beyond the end of the flame may be read at the point where the appropriate % excess air curve intersects the zero available heat line.

Attachment 2-11. Variation in furnace losses with air-to-fuel ratio[4]



Attachment 2-12. Rate of chemical reactions


Reactants
Activated complex
Products
A + B
AB*
C + D
ΔE
Energy
T_1 < T_2
Reaction coordinates
No. of molecules
No. of molecules

Rate: R + k[A][B]

React. vel. const. **k = function of T, ΔE, ...**

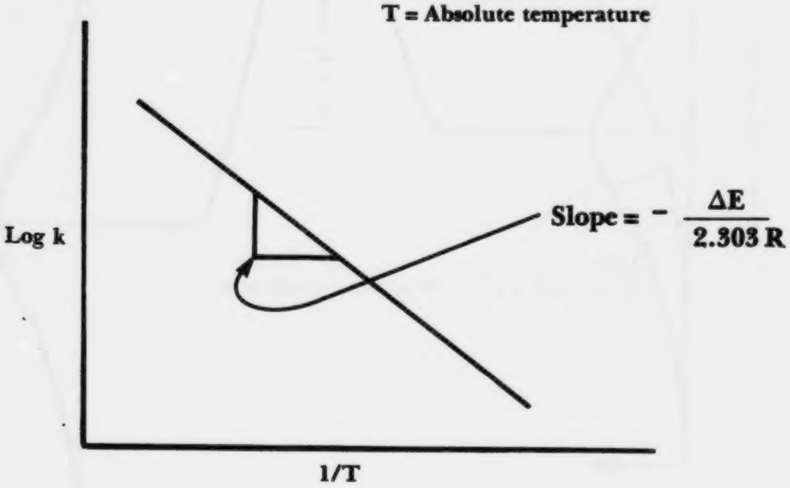
Attachment 2-13. Temperature effect on reaction rate

Arrhenius equation:

$$\boxed{k = a\, e^{-\frac{\Delta E}{RT}}}$$

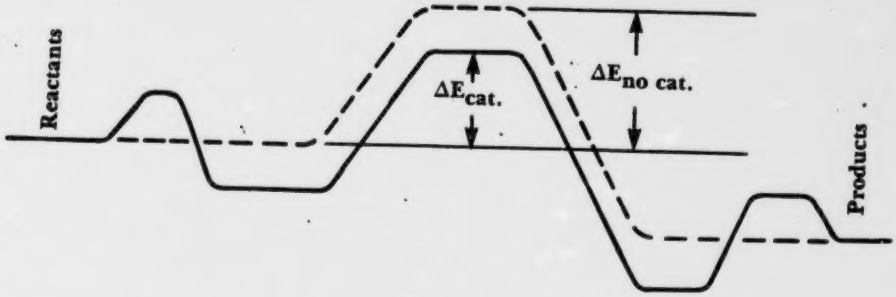
Where:

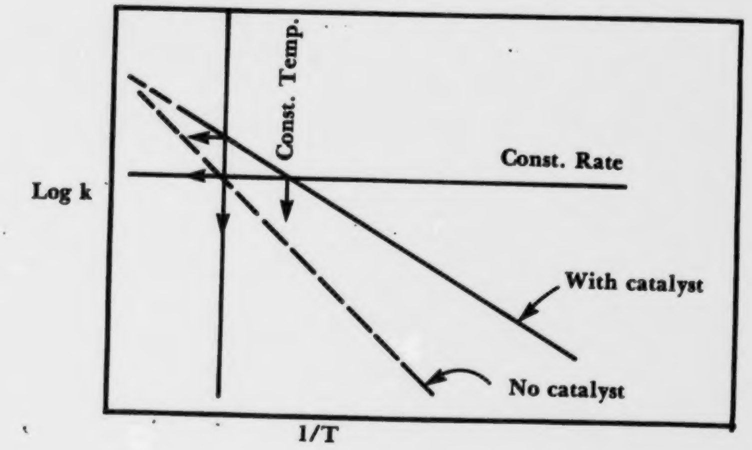
k = Reaction velocity constant
a = Frequency
ΔE = Activation energy
R = Gas constant
T = Absolute temperature



Attachment 2-14. Effect of catalyst on reaction rate

$$A + B \rightleftharpoons (A + B)_{ADS} \rightleftharpoons (AB)^{*}_{ADS} \rightleftharpoons (C + D)_{ADS} \rightleftharpoons C + D$$


Reactants
$\Delta E_{cat.}$
$\Delta E_{no\ cat.}$
Products



Chapter 3

Fuel Properties

INTRODUCTION

This chapter presents the various physical and chemical properties of fuels used in stationary combustion equipment. The three dominant fuels are coal, fuel oil, and natural gas; however, there are a number of other fuels which are important in particular industries and regions.

Fuels typically are classified as solid, liquid, and gaseous fuel. Gaseous fuels have an advantage, in that their rate of combustion is rapid, being fundamentally limited by the diffusion or mixing of air (oxygen) with the gas.

Liquid fuels burn in a gaseous form, therefore the rate of combustion of liquid fuels is limited by their rate of evaporation (or distillation). Some liquid fuels are very volatile (vaporize easily) and others, such as No. 6 fuel oil, require special conditioning.

Solid fuels burning is limited by two phenomena. The volatile matter fraction of a solid fuel is distilled off and burns as a gas. The remaining fixed-carbon fraction burns as a solid, with the rate of combustion limited by the diffusion of oxygen to the surface.

Fuel properties are important variables influencing both combustion design and various operational considerations. Complete combustion, with the lowest practical amount of excess air (maximum fuel economy) and the lowest emission of air pollutants, requires control of fuel properties, as well as other parameters.

The heating value of fuels may be determined experimentally in devices which operate at either constant volume (bomb calorimeter) or constant pressure (continuous flow gas calorimeter). Because of the possible loss of energy due to expanding gases, the constant volume values may be higher than constant pressure values.

The higher heating value (also called the gross heat of combustion, and the total heat of combustion) is the measured energy release (Btu/lb or Btu/gal) when products of combustion are cooled to standard temperature and the water vapor is condensed.

The lower heating value is energy released when products of combustion are cooled to standard temperature, and all water is vapor. This value is computed from the experimentally determined higher heating value.

The lower flammability (or explosive) limit is the minimum concentration (% volume) of gases or vapors in air below which flame propogation will not occur. There is also a maximum limit on concentration of gases or vapors in air above which flame propagation will not occur. A mixture between the lower and upper flammability limits will support a flame or explode! Typical safe practice is to maintain waste gas or vapor concentrations at less than 25% of the lower flammability limit. It is important to provide oxygen-free storage with delivery of the material to a combustion system where oxygen is added and the combustion controlled. The lack of homogeneity within a mixture can result in localized explosive conditions although the average concentration would appear to be safe.

Gaseous Fuels

Gaseous fuels are composed of mixtures of gaseous components as illustrated in Attachment 3-1. Natural gas is the typical gaseous fuel burned. It has a higher heating value (around 1,000 Btu/scf) which depends on the chemical composition (or the source). Methane is the primary constituent of natural gas.

Natural gas is thought of as a sulfur-free fuel. However, as it comes from the well, natural gas may contain sulfur (mercaptans and hydrogen sulfide) and will be "sour." Through a refining process, the sulfur products are removed, and the gas is then called "sweet."

Liquefied petroleum gas (LPG) is a group of hydrocarbon materials which are gaseous under normal atmospheric conditions. However, they may be liquefied under moderate pressure (80 to 200 psig). This is a considerable advantage in shipping considerations, because the chemical energy storage on a volume basis is considerably increased. LPG is composed of blends of paraffinic (saturated) hydrocarbons such as propane, isobutane, and normal butane. These are gases which are derived from natural gas or from petroleum refinery operations.

Refinery gas is a byproduct blend of gases typically produced in a petroleum refinery and used for process heating. The heating value and composition may vary widely, depending on the particular refining process.

Coke oven gas, illustrated in Attachment 3-2, is one of the gaseous fuels derived from coal. Coke oven gas is given off from bituminous coal in the coke carbonization process (at high temperatures in the absence of air). The properties of coke oven gas vary with the coal, temperature, time, and the other conditions of the operation. Typically coke oven gas has heating values which range from 450 to 650 Btu/scf.

Producer gas is derived from the partial oxidation of coal or coke. Typical heating values range from 140 to 180 Btu/scf.

Other synthetic gases used in petroleum and metallurgical operations include carburetted water gas, regenerator waste gas, and blast furnace gas.

Liquid Fuels

Naturally occurring crude oil, although combustible, is refined into various petrochemical products for economic and combustion safety reasons. In addition to fuel oils, various gasolines, solvents, and chemicals are produced from distillation, cracking, and reforming processes.

The standard grades of fuel oils for stationary combustion equipment are described in Attachment 3-3. Note that No.2 fuel oil is the distillate oil commonly used for domestic heating purposes, and that No.6 fuel oil (Bunker C) is used primarily in industrial heating and power generating. Example properties for each grade are in Attachment 3-4.

An important property of fuel oils is specific gravity, the ratio of the weight of a volume of oil at 60°F to the weight of an equal volume of water. Specific gravity is important because it provides an indication of the chemical composition and heating value of the oil. As the hydrogen content increases, the specific gravity decreases, the combustion energy released per pound increases, but the energy released per gallon decreases.

For example, refer to Attachment 3-5 and consider a No.6 fuel oil having a specific gravity of 0.9861. The total heat of combustion is 18,640 Btu/lb. A No.2 fuel oil having a specific gravity of 0.8654 would have 19,490 Btu/lb. The denser fuel oil has a lower hydrogen content and a smaller heating value on a mass basis. However, on a volume basis (Btu/gal at 60°F) the No.6 has a higher value.

Instead of specific gravity, the API degree scale is commonly used in oil specifications. It is inversely related to the specific gravity at 60°F:

$$\textit{Degrees API} = \frac{141.5}{sp.\ gr.\ @60^{\circ}F} - 131.5$$

The flash point is an important safety related property. it is the lowest temperature at which an oil gives off sufficient vapor to cause a flash or explosion when a flame is brought near the oil surface. The concern about flash point is illustrated by the fact that No.6 fuel oil typically is heated (for pumping or atomizing reasons) to a temperature (up to 210°F) which is higher than the flash point of a No.2 fuel oil (100°F). If a No.2 oil were placed in the tank for No. 6 oil, and if the heaters accidentally were not disabled, a serious explosion could occur. Explosions of this type were recorded when units formerly burning No.6 were converted, because of air pollution concerns, to burn No.2.

Viscosity is the measure of a fluid's internal friction or resistance to flow. As illustrated in Attachment 3-6, viscosity is reduced as the temperature is increased. Various standard experimental measurement techniques have been adopted for viscosity. The Saybolt Universal Scale (SUS) and Saybolt Furol Scale (SFS) indicate the length of time required for a given quantity of oil to pass through a particular sized orifice. A sample of oil at a given temperature will have a lower SFS value than SUS, because the orifice size of the Furol test is much larger. Note that the vertical scale of Attachment 3-6 has been made non-linear. This assists one in approximating the viscosity/temperature change of a given oil (by locating a given viscosity/temperature point and projecting a line through the point, parallel to the sloping lines shown).

If a No.5 or No.6 fuel oil has too high a viscosity when it reaches the atomizer, the droplets formed will be too large. Incomplete combustion can occur, because larger drops may not have enough time to burn because of an inadequate rate of evaporation. The evaporation rate depends on the total area available, and big drops have much less total area than would many small drops of an equivalent total mass.

Sulfur in fuel oil is a primary air pollution concern, in that most of the fuel sulfur becomes SO_2 which is emitted with the flue gas. Some of the sulfur, however, may produce acidic emissions which cause dew-point problems and corrosion of the metal furnace surfaces (economizers, air heaters, ducts, etc.) Sulfur can be removed from fuel oil by refining operations. Other trace elements which may be contained in fuel oils are vanadium and sodium. The influences of these materials on air pollution emissions will be discussed in Chapter 8.

Diesel fuels classified as 1D, 2D, and 4D are very similar to No.1, 2, and 4 fuel oils respectively, as can be surmised from Attachment 3-7. In many situations they may be used interchangeably. The main difference arises from the necessity for greater uniformity in diesel fuels, which is obtained by specifying cetane rating, sulfur, and ash restrictions for diesel operation.

The cetane number is one measure of the auto-ignition quality of fuels for diesel (compression ignition) engines. Most high-speed diesels require fuels with cetane values from 50 to 60. Cetane ratings below 40 may cause exhaust smoke, increased fuel consumption, and loss of power (3).

Smoke and exhaust odor are directly affected by fuel volatility. The more volatile diesel fuels vaporize rapidly and mix better in the combustion zone. The distillation temperatures for different fractions of the fuel provide an indication of fuel volatility. A low 50% distillation temperature will prevent smoke, and a low 90° distillation temperature (e.g. 575°F) will ensure low carbon residuals (3). End point distillation temperatures less than 700°F are desirable.

Stationary gas turbines are designed for constant speed and operation and may be designed to burn gas or a distillate fuel oil such as No.2 or 2D. Larger units are designed to burn heavy residual oils. The major requirements are for the fuel and products of combustion to be nondepositing and noncorrosive.

For variable-speed and variable-load gas turbines special fuel specifications are required. Kerosene is the general fuel commonly used for such applications. It has an endpoint temperature of 572°F (max), a flash point of 121 (min), and a very low aromatic content. It is similar to the Jet A and JP-1 fuels, as indicated in Attachment 3-8. Aircraft turbojets operate at high altitudes with low air temperatures; therefore, fuel freezing, volatility, and boiling temperatures are important requirements (4).

Solid Fuels

Coal is the most abundant energy resource of the USA. Unfortunately, coal is a fuel which may have high nitrogen, sulfur, and ash content, relative to other fuels. Control of air pollution emissions from coal may include the techniques of fuel modification, combustion modification, and flue gas cleaning.

As illustrated in Attachment 3-9 and 3-10, coal is generally classified as anthracite, bituminous, subbituminous, or lignite. Anthracite coal has the highest fixed carbon, and lignite coals have the lowest calorific value, as shown by example in Attachment 3-11.

Because the composition and properties of coal are variable, depending on the source, standard sampling and laboratory procedures have been established by ASTM.

As illustrated in Attachment 3-12, the ultimate analysis provides the percentage by weight of elemental carbon, hydrogen, nitrogen, oxygen, sulfur, and total ash in the coal. The proximate analysis provides the fractions of a coal sample that are mositure, volatile matter, fixed carbon, and ash. In addition, the heating value is typically included.

The above-mentioned coal analysis may be given on an "as received" basis. However, a "moisture free" or "dry" basis removes the influence of moisture from the tabulated numbers, thereby removing a variable which changes with handling and exposure conditions.

Surface moisture is the moisture (percent by weight) of coal which is removed by drying in air at 18 to 27°F (10 to 15°C) above room temperature. The "total moisture" includes the surface moisture and the moisture removed by oven drying at 216 to 230°F (104 to 110°C) for one hour. However, the "total moisture" does not include water decomposition (combined water) and water of hydration, which are part of the volatile matter in the proximate analysis and part of the hydrogen and oxygen content in the ultimate analysis.

Volatile matter is the gaseous material driven off when coal is heated to a standard temperature. It is composed of hydrocarbons and other gases from distillation and decomposition.

Fixed carbon is the combustible fraction remaining after the volatiles are removed. The ash is the noncombustible residue remaining after complete combustion of the coal. This is not to be confused with fly ash, which is airborne particulate composed of both ash and some combustible material (carbon).

Sulfur in coal is in both organic and inorganic forms. Inorganic forms include metal sulfides (pyrite and marcasite) and metal sulfates (gypsum and barite). About half of the sulfur in coal is in pyritic form and half is organic. Pyrite is a dense, small crystal which may be removed mechanically by gravimetric techniques. Organic sulfur is more difficult (expensive) to remove.

Ash-softening temperature is used to identify coal likely to form clinkers on the fuel bed and slag on boiler tubes and superheaters. A low ash-fusion temperature is desirable for removal of ash from slagging (wet bottom) furnaces.

Caking coals have a high agglomerating index and burn poorly on a grate because they become plastic and fuse together. On the other hand, free burning coals burn as separate pieces of fuel without agglomerating.

Grindability index measures the ease of pulverizing coal. The free-swelling index is a measure of the behavior of rapidly heated coal which provides an indication of the tendency of coal to coke.

Coke is a porous fuel formed by destructive heating of coal in the absence of air. Attachment 3-13 illustrates the fact that the properties of coke depend on the coking operational conditions.

Petroleum coke, coal tar (liquid), and coal tar pitch are other by-product fuels which may be burned in industrial boilers.

Wood is composed mainly of cellulose and water. Wet wood, wood chips, saw dust, bark, and hogged fuel have a wide range of moisture contents from 4 to 75%, as illustrated in Attachments 3-14 and 3-15. Special drying or blending maybe required for proper combustion of wood wastes.

Bagasse is fibrous sugar cane stalk (after sugar juices are removed). Bagasse has high moisture (40 to 60%) and relatively high ash due to silt picked up in harvesting (see Attachment 3-16).

Municipal solid waste is a fuel often used for production of steam. Except for the presence of glass and metals, solid waste is very similar to hogged wood fuel. The composition of municipal wastes vary considerably (the moisture varies particularly with exposure). Average values of composition and analysis are presented in Attachment 3-17.

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Attachment 3-1. Analyses of samples of natural gas2

Sample No. Source of Gas	1 Pa.	2 So. Cal.	3 Ohio	4 La.	5 Okla.
Analyses					
Constituents, % by vol					
H_2 Hydrogen	—	—	1.82	—	—
CH_4 Methane	83.40	84.00	93.33	90.00	84.10
C_2H_4 Ethylene	—	—	0.25	—	—
C_2H_6 Ethane	15.80	14.80	—	5.00	6.70
CO Carbon monoxide	—	—	0.45	—	—
CO_2 Carbon dioxide	—	0.70	0.22	—	0.80
N_2 Nitrogen	0.80	0.50	3.40	5.00	8.40
O_2 Oxygen	—	—	0.35	—	—
H_2S Hydrogen sulfide	—	—	0.18	—	—
Ultimate, % by wt					
S Sulfur	—	—	0.34	—	—
H_2 Hydrogen	23.53	23.30	23.20	22.68	20.85
C Carbon	75.25	74.72	69.12	69.26	64.84
N_2 Nitrogen	1.22	0.76	5.76	8.06	12.90
O_2 Oxygen	—	1.22	1.58	—	1.41
Specific gravity (rel to air)	0.636	0.636	0.567	0.600	0.630
Higher heat value					
Btu/cu ft @ 60F & 30 in. Hg	1,129	1,116	964	1,002	974
Btu/lb of fuel	23,170	22,904	22,077	21,824	20,160

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Attachment 3-2. Selected analysis of gaseous fuels derived from coal[2]

Analyses, % by vol		Coke-oven gas	Blast-furnace gas	Carbureted water gas	Producer gas
H_2	Hydrogen	47.9%	2.4%	34.0%	14.0%
CH_4	Methane	33.9	0.1	15.5	3.0
C_2H_4	Ethylene	5.2	—	4.7	—
CO	Carbon monoxide	6.1	23.3	32.0	27.0
CO_2	Carbon dioxide	2.6	14.4	4.3	4.5
N_2	Nitrogen	3.7	56.4	6.5	50.9
O_2	Oxygen	0.6	—	0.7	0.6
C_6H_6	Benzene	—	—	2.3	—
H_2O	Water	—	3.4	—	—
Specific gravity (relative to air)		0.413	1.015	0.666	0.857
Higher heat value—Btu/cu ft					
@ 60F & 30in. Hg		590	—	534	163
@ 80F & 30in. Hg		—	83.8	—	—

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Attachment 3-3. Detailed requirements for fuel oils[1]

Grade of Fuel Oil[b]	Flash Point, F	Pour Point, F	Water and Sediment, per cent by volume	Carbon Residue on 10 per cent Bottoms, per cent	Ash, per cent by weight	Distillation Temperatures, F			Saybolt Viscosity, sec				Kinematic Viscosity, centistokes				Gravity, deg API	Copper Strip Corrosion
						10 per cent Point	90 per cent Point		Universal at 100 F		Furol at 122 F		At 100 F		At 122 F			
	Min	Max	Max	Max	Max	Max	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Min	Max
No. 1 A distillate oil intended for vaporising pot-type burners and other burners requiring this grade of fuel	100 or legal	0	trace	0.15	...	420	550	...	...	...	...	...	2.2	1.4	...	...	35	No. 3
No. 2 A distillate oil for general purpose domestic heating for use in burners not requiring No. 1 fuel oil	100 or legal	20[c]	0.10	0.35	...	[d]	640[e]	540[e]	37.93	32.6	...	...	(3.6)[e]	(2.0)[e]	...	...	30[g]	...
No. 4 An oil for burner installations not equipped with preheating facilities	130 or legal	20	0.50	...	0.10	...	...	...	125	45	...	...	(26.4)	(5.8)	...	...	...	...
No. 5 A residual-type oil for burner installations equipped with preheating facilities	130 or legal	...	1.00	...	0.10	...	...	...	...	150	40	...	...	(32.1)	(81)	...	...	...
No. 6 An oil for use in burners equipped with preheaters permitting a high-viscosity fuel	150	...	2.00[f]	...	...	...	...	...	...	...	300	45	...	...	(638)	(92)	...	...

[a] Recognizing the necessity for low sulfur fuel oils used in connection with heat treatment, nonferrous metal, glass, and ceramic furnaces and other special uses, a sulfur requirement may be specified in accordance with the following table.

Grade of Fuel Oil	Sulfur, max, per cent
No. 1	0.5
No. 2	1.0
No. 4	no limit
No. 5	no limit
No. 6	no limit

Other sulfur limits may be specified only by mutual agreement between the purchaser and the seller.

[b] It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next lower grade unless in fact it meets all requirements of the lower grade.

[c] Lower or higher pour points may be specified whenever required by conditions of storage or use. However, these specifications shall not require a pour point lower than 0 F under any conditions.

[d] The 10 per cent distillation temperature point may be specified at 440 F maximum for use in other than atomizing burners.

[e] When pour point less than 0 F is specified, the minimum viscosity shall be 1.8 cs (32.0 sec, Saybolt Universal) and the minimum 90 per cent point shall be waived.

[f] The amount of water by distillation plus the sediment by extraction shall not exceed 2.00 per cent. The amount of sediment by extraction shall not exceed 0.50 per cent. A deduction in quantity shall be made for all water and sediment in excess of 1.0 per cent.

[g] In the states of Alaska, Arizona, California, Hawaii, Idaho, Nevada, Oregon, Utah and Washington, a minimum gravity of 28 deg API is permissible

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Attachment 3-4. Typical analyses and properties of fuel oils[1]

Grade	No. 1 Fuel Oil	No. 2 Fuel Oil	No. 4 Fuel Oil	No. 5 Fuel Oil	No. 6 Fuel Oil
Type	Distillate (Kerosene)	Distillate	Very Light Residual	Light Residual	Residual
Color	Light	Amber	Black	Black	Black
API gravity, 60 F	40	32	21	17	12
Specific gravity, 60/60 F	0.8251	0.8654	0.9279	0.9529	0.9861
Lb per U.S. gallon, 60 F	6.870	7.206	7.727	7.935	8.212
Viscos., Centistokes, 100 F	1.6	2.68	15.0	50.0	360.0
Viscos., Saybolt Univ., 100 F	31	35	77	232	—
Viscos., Saybolt Furol, 122 F	—	—	—	—	170
Pour point, F	Below zero	Below zero	10	30	65
Temp. for pumping, F	Atmospheric	Atmospheric	15 min.	35 min.	100
Temp. for atomizing, F	Atmospheric	Atmospheric	25 min.	130	200
Carbon residue, per cent	Trace	Trace	2.5	5.0	12.0
Sulfur, per cent	0.1	0.4–0.7	0.4–1.5	2.0 max.	2.8 max.
Oxygen and nitrogen, per cent	0.2	0.2	0.48	0.70	0.92
Hydrogen, per cent	13.2	12.7	11.9	11.7	10.5
Carbon, per cent	86.5	86.4	86.10	85.55	85.70
Sediment and water, per cent	Trace	Trace	0.5 max.	1.0 max.	2.0 max.
Ash, per cent	Trace	Trace	0.02	0.05	0.08
Btu per gallon	137,000	141,000	146,000	148,000	150,000

* Technical information from Humble Oil & Refining Company.

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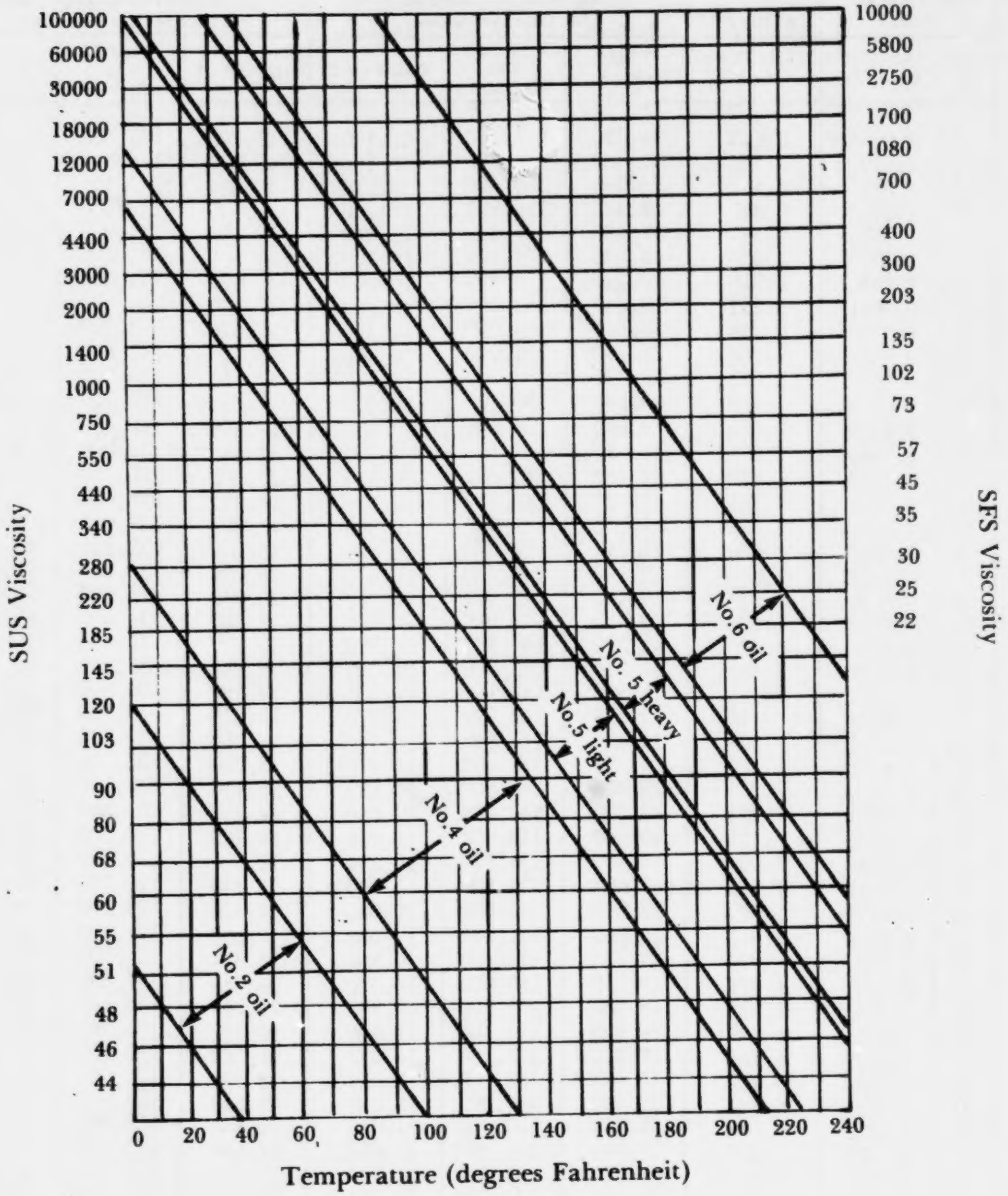
Attachment 3-5. Gravities, densities, and heats of combustion of fuel oils[6]

VALUES FOR 10 TO 49 DEG API, INCLUSIVE, REPRINTED FROM BUREAU OF STANDARDS MISCELLANEOUS PUBLICATION NO. 97, "THERMAL PROPERTIES OF PETROLEUM PRODUCTS."

GRAVITY AT 60/60 F		DENSITY AT 60 F	TOTAL HEAT OF COMBUSTION (At Constant Volume)			NET HEAT OF COMBUSTION (At Constant Pressure)		
DEG API	SPECIFIC GRAVITY	LB PER GAL	BTU PER LB	BTU PER GAL AT 60 F	CAL PER G	BTU PER LB	BTU PER GAL AT 60 F	CAL PER G
5	1.0366	8.643	18,250	157,700	10,140	17,290	149,400	9,610
6	1.0291	8.580	18,330	157,300	10,180	17,340	148,800	9,650
7	1.0217	8.518	18,390	156,600	10,210	17,390	148,100	9,670
8	1.0143	8.457	18,440	155,900	10,240	17,440	147,500	9,700
9	1.0071	8.397	18,490	155,300	10,270	17,490	146,900	9,720
10	1.0000	8.337	18,540	154,600	10,300	17,540	146,200	9,740
11	0.9930	8.279	18,590	153,900	10,330	17,580	145,600	9,770
12	0.9861	8.221	18,640	153,300	10,360	17,620	144,900	9,790
13	0.9792	8.164	18,690	152,600	10,390	17,670	144,200	9,810
14	0.9725	8.108	18,740	152,000	10,410	17,710	143,600	9,840
15	0.9659	8.053	18,790	151,300	10,440	17,750	142,900	9,860
16	0.9593	7.998	18,840	150,700	10,470	17,790	142,300	9,880
17	0.9529	7.944	18,890	150,000	10,490	17,820	141,600	9,900
18	0.9465	7.891	18,930	149,400	10,520	17,860	140,900	9,920
19	0.9402	7.839	18,980	148,800	10,540	17,900	140,300	9,940
20	0.9340	7.787	19,020	148,100	10,570	17,930	139,600	9,960
21	0.9279	7.736	19,060	147,500	10,590	17,960	139,000	9,980
22	0.9218	7.686	19,110	146,800	10,620	18,000	138,300	10,000
23	0.9159	7.636	19,150	146,200	10,640	18,030	137,700	10,020
24	0.9100	7.587	19,190	145,600	10,660	18,070	137,100	10,040
25	0.9042	7.538	19,230	145,000	10,680	18,100	136,400	10,050
26	0.8984	7.490	19,270	144,300	10,710	18,130	135,800	10,070
27	0.8927	7.443	19,310	143,700	10,730	18,160	135,200	10,090
28	0.8871	7.396	19,350	143,100	10,750	18,190	134,600	10,110
29	0.8816	7.350	19,380	142,500	10,770	18,220	133,900	10,120
30	0.8762	7.305	19,420	141,800	10,790	18,250	133,300	10,140
31	0.8708	7.260	19,450	141,200	10,810	18,280	132,700	10,150
32	0.8654	7.215	19,490	140,600	10,830	18,310	132,100	10,170
33	0.8602	7.171	19,520	140,000	10,850	18,330	131,500	10,180
34	0.8550	7.128	19,560	139,400	10,860	18,360	130,900	10,200
35	0.8498	7.085	19,590	138,800	10,880	18,390	130,300	10,210
36	0.8448	7.043	19,620	138,200	10,900	18,410	129,700	10,230
37	0.8398	7.001	19,650	137,600	10,920	18,430	129,100	10,240
38	0.8348	6.960	19,680	137,000	10,940	18,460	128,500	10,260
39	0.8299	6.920	19,720	136,400	10,950	18,480	127,900	10,270
40	0.8251	6.879	19,750	135,800	10,970	18,510	127,300	10,280
41	0.8203	6.839	19,780	135,200	10,990	18,530	126,700	10,300
42	0.8155	6.799	19,810	134,700	11,000	18,560	126,200	10,310
43	0.8109	6.760	19,830	134,100	11,020	18,580	125,600	10,320
44	0.8063	6.722	19,860	133,500	11,030	18,600	125,000	10,330
45	0.8017	6.684	19,890	132,900	11,050	18,620	124,400	10,340
46	0.7972	6.646	19,920	132,400	11,070	18,640	123,900	10,360
47	0.7927	6.609	19,940	131,900	11,080	18,660	123,300	10,370
48	0.7883	6.572	19,970	131,200	11,100	18,680	122,800	10,380
49	0.7839	6.536	20,000	130,700	11,110	18,700	122,200	10,390

Attachment 3-6. Approximate viscosity of fuel oil[5]



Attachment 3-7. Diesel fuel oil specifications[7]

Requirements	Distillate fuel oils				4	4D	Residual fuel oils	
	1	1D	2	2D			5	6
Cetane rating, min		40		40		30		
Flash point, min. °F	100	100	100	125	130	130	130	150
Pour point, max. °F	0		20		20			
Viscosity, min-max. SU see 100 °F	30-34	30-34	33-38	33-45	45-125	45-125	350-750	900-9000
APl. min	35		30					
ASTM distillation, °F, 10%, max	420							
90%, max, or min-max	550	550	540-640	540-675				
C on 10% bottoms, percent, mass	0.15	0.15	0.35	0.35				
Ash, percent, mass		0.01		0.02	0.10	0.10	0.10	
Water, sediment, percent, vol	Trace	Trace	0.10	0.10	0.50	0.50	1.00	2.00
Sulfur, percent, mass		0.50		1.0		2.0		

Attachment 3-8. Aviation turbine oils[7]

Requirement	ASTM D1655		Mil-J-5624					Mil-F-4600A§
Designation	Jet A	Jet B	JP-1	JP-3	JP-4	JP-5	JP-6	CITE-11
Flash point, °F (min-max)	110-150		110(min)			140(min)		
Freezing point, °F (max)	− 40 +	− 60	− 76	− 76	− 55	− 65	− 67	
Gravity, APl (min-max)	39-51	45-57	3.5(max)	50-60	45-57	36-48	37-50	
Vapor pressure, Reid psig (min-max)		0-3		5-7	2-3			3
Distillation, °F								
10 percent max	400		410			400		200
20 percent max		290		240	290			
50 percent max	450	370		350	370			325
90 percent max		470	490	470	470			
EP max	550		572			550		550
Heating value, lower, (Btu/lb$_m$) min	18,400	18,400	18,300	18,400	18,400	18,300	18,400	
Sulfur, (percent by mass)(max)	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.4
Smoke point, ‡ mm (min)	25					20		
Aromatics, vol. percent, (max)	20	20	20	25	25	25	25	25
Potential gum, mg/100 ml (max)	14	14	8	14	14	14	14	14

Attachment 3-9. United States coal reserves by states, 1970[2] (million tons)

State	Bituminous	Sub-bituminous	Lignite	Anthracite	Total
Alabama	13,518	0	20	0	13,538
Alaska	19,415	110,674	0	0	130,089
Arkansas	1,640	0	350	430	2,420
Colorado	62,389	18,248	0	78	80,715
Georgia	18	0	0	0	18
Illinois	139,756	0	0	0	139,756
Indiana	34,779	0	0	0	34,779
Iowa	6,519	0	0	0	6,519
Kansas	18,686	0	0	0	18,686
Kentucky	65,958	0	0	0	65,958
Maryland	1,172	0	0	0	1,172
Michigan	205	0	0	0	205
Missouri	23,359	0	0	0	23,359
Montana	2,299	131,877	87,525	0	221,701
New Mexico	10,760	50,715	0	4	61,479
North Carolina	110	0	0	0	110
North Dakota	0	0	350,680	0	350,680
Ohio	41,862	0	0	0	41,862
Oklahoma	3,299	0	0	0	3,299
Oregon	48	284	0	0	332
Pennsylvania	57,533	0	0	12,117	69,650
South Dakota	0	0	2,031	0	2,031
Tennessee	2,652	0	0	0	2,652
Texas	6,048	0	6,878	0	12,926
Utah	32,100	150	0	0	32,250
Virginia	9,712	0	0	335	10,047
Washington	1,867	4,194	117	5	6,183
West Virginia	102,034	0	0	0	102,034
Wyoming	12,699	103,011	0	0	120,710
Other States	618	4,057	46	0	4,721
Total	671,055	428,210	447,647	12,969	1,559,881

Source, Bureau of Mines.

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Attachment 3-10. ASTM classification of coals by rank[2]

Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	—	—	2	—	—	Nonagglomerating
	2. Anthracite	92	98	2	8	—	—	
	3. Semianthracite[c]	86	92	8	14	—	—	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	—	—	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	—	—	
	3. High volatile *A* bituminous coal	—	69	31	—	14,000[d]	—	
	4. High volatile *B* bituminous coal	—	—	—	—	13,000[d]	14,000	
	5. High volatile *C* bituminous coal	—	—	—	—	11,500 10,500[e]	13,000 11,500	Agglomerating
III. Subbituminous	1. Subbituminous *A* coal	—	—	—	—	10,500	11,500	Nonagglomerating
	2. Subbituminous *B* coal	—	—	—	—	9,500	10,500	
	3. Subbituminous *C* coal	—	—	—	—	8,300	9,500	
IV. Lignitic	1. Lignite *A*	—	—	—	—	6,300	8,300	
	2. Lignite *B*	—	—	—	—	—	6,300	

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile *C* bituminous group.

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Attachment 3-11. Selected coal analysis[2]

Coal	Location	Moisture	Volatile Matter	Fixed Carbon	Ash	Sulfur	High Heating Value
Anthracite	Lackawanna Co., PA	2.5	6.2	79.4	11.9	0.60	12,925
Low-Vol. Bituminous	McDowell Co., WV	1.0	16.2	77.3	5.1	0.74	14,715
High-Vol. Bituminous	Westmoreland Co., PA	1.5	30.7	56.6	11.2	1.82	13,325
Subbituminous A	Musselshell Co , MT	14.1	32.2	46.7	7.0	0.43	11,140
Subbituminous C	Campbell Co., WY	31.0	31.4	32.8	4.8	0.55	8,320
Lignite A	Mercer Co., ND	37.0	37.0	32.2	4.2	0.40	7,255

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Attachment 3-12. Example coal analyses[2]

Component	Weight, %
Moisture (Free)	2.5
Volatile matter	37.6
Fixed carbon	52.9
Ash	7.0
Total	100.0
Heating value, Btu/lb	13,000

Component	Weight, %
Moisture (Free)	2.5
Carbon	75.0
Hydrogen	5.0
Sulfur	2.3
Nitrogen	1.5
Oxygen	6.7
Ash	7.0
Total	100.0

Component	Weight, %
Carbon	76.9
Hydrogen	5.1
Sulfur	2.4
Nitrogen	1.5
Oxygen	6.9
Ash	7.2
Total	100.0

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Attachment 3-13. Analyses of typical U.S. coke, as fired[1]

	Proximate analysis percent				Ultimate analysis percent							Heating value Btu per lb.			
	Moisture	Vol. matter	Fixed carbon	Ash	Moisture H_2O	Carbon C	Hydrogen H_2	Sulfur S	Oxygen O_2	Nitrogen N_2	Ash	Higher	Lower	Atmos. cir at zero excess air, lb/10^6 Btu	CO_2 at zero excess air, percent
High temperature coke	5.0	1.3	83.7	10.0	5.0	82.0	0.5	0.8	0.7	1.0	10.0	12200	12095	796	20.7
Low temperature coke	2.8	15.1	72.1	10.0	2.8	74.5	3.2	1.8	6.1	1.6	10.0	12600	12258	763	19.3
Beehive coke	0.5	1.8	86.0	11.7	0.5	84.4	0.7	1.0	0.5	1.2	11.7	12527	12453	805	20.5
Byproduct coke	0.8	1.4	87.1	10.7	0.8	85.0	0.7	1.0	0.5	1.3	10.7	12690	12613	801	20.5
High temp. coke breeze	12.0	4.2	65.8	18.0	12.0	66.8	1.2	0.6	0.5	0.9	18.0	10200	9950	805	20.1
Gas works coke: horiz. retorts	0.8	1.4	88.0	9.8	0.8	86.8	0.6	0.7	0.2	1.1	9.8	12820	12753	807	20.6
Vertical retorts	1.3	2.5	86.3	9.9	1.3	85.4	1.0	0.7	0.3	1.4	9.9	12770	12659	810	20.4
Narrow coke ovens	0.7	2.0	85.3	12.0	0.7	84.6	0.5	0.7	0.3	1.2	12.0	12550	12493	802	20.6
Petroleum coke	1.1	7.0	90.7	1.2	1.1	90.8	3.2	0.8	2.1	0.8	1.2	15060	14737	773	19.5
Pitch coke	0.3	1.1	97.6	1.0	0.3	96.6	0.6	0.5	0.3	0.7	1.0	14097	14036	813	20.7

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Attachment 3-14. Typical analyses of wood, dry[1]

	Percent by weight						Heating value Btu per lb.		Atmos. air at zero excess air lb/10^6 Btu	CO_2 at zero excess air, percent
	Carbon C	Hydrogen H_2	Sulfur S	Oxygen O_2	Nitrogen N_2	Ash	Higher	Lower		
Softwoods**										
Cedar, white	48.80	6.37	–	44.47	–	0.37	8400*	7780	709	20.2
Cypress	54.98	6.54	–	38.08	–	0.40	9870*	9234	712	19.5
Fir, Douglas	52.3	6.3	–	40.5	0.1	0.8	9050	8438	719	19.9
Hemlock, Western	50.4	4.8	0.1	41.4	0.1	2.2	8620	8056	705	20.4
Pine, pitch	59.00	7.19	–	32.68	–	1.13	11320*	10620	702	18.7
white	52.55	6.08	–	41.25	–	0.12	8900*	8308	722	20.2
yellow	52.60	7.02	–	40.07	–	1.31	9610*	8927	709	19.2
Redwood	53.5	5.9	–	40.3	0.1	0.2	8840	8266	707	20.2
Hardwoods**										
Ash, white	49.73	6.93	–	43.04	–	0.30	8920*	8246	709	19.5
Beech	51.64	6.26	–	41.45	–	0.65	8260*	8151	728	20.1
Birch, white	49.77	6.49	–	43.45	–	0.29	8650*	8019	714	20.0
Elm	50.35	6.57	–	42.34	–	0.74	8810*	8171	717	19.8
Hickory	49.67	6.49	–	43.11	–	0.73	8670*	8039	712	19.9
Maple	50.64	6.02	–	41.74	0.25	1.35	8580	7995	719	20.3
Oak, black	48.78	6.09	–	44.98	–	0.15	8180*	7587	713	20.5
red	49.49	6.62	–	43.74	–	0.15	8690*	8037	711	19.9
white	50.44	6.59	–	42.73	–	0.24	8810*	8169	713	19.8
Poplar	51.64	6.26	–	41.45	–	0.65	8920*	8311	715	20.0

* Calculated from reported higher heating value of kiln-dried wood assumed to contain eight percent moisture.

**The terms hard and soft wood, contrary to popular conception, have no reference to the actual hardness of the wood. According to the Wood Handbook, prepared by the Forest Products Laboratory of the U.S. Department of Agriculture, hardwoods belong to the botanical group of trees that are broad leaved whereas softwoods belong to the group that have needle or scalelike leaves, such as evergreens; cypress, larch and tamarack are exceptions.

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Attachment 3-15. Analyses of hogged fuels[1]

Kind of fuel		Western Hemlock	Douglas Fir	Pine Sawdust
Moisture as received	Percent	57.9	35.9	—
Moisture air dried	"	7.3	6.5	6.3
Proximate analysis, dry fuel				
Volatile matter	Percent	74.2	82.0	79.4
Fixed carbon	"	23.6	17.2	20.1
Ash	"	2.2	0.8	0.5
Ultimate analysis, dry fuel				
Hydrogen	Percent	5.8	6.3	6.3
Carbon	"	50.4	52.3	51.8
Nitrogen	"	0.1	0.1	0.1
Oxygen	"	41.4	40.5	41.3
Sulfur	"	0.1	0	0
Ash	"	2.2	0.8	0.5
Heating value, dry	Btu per lb	8620	9050	9130

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Attachment 3-16. Typical analyses of bagasse[1]

	Percent by weight					Heating value Btu per lb		Atmos. air at zero excess air lb per 10^6 Btu	CO_2 at zero excess air percent
	Carbon C	Hydrogen H_2	Oxygen N_2	Nitrogen N_2	Ash	Higher	Lower		
Cuba	43.15	6.00	47.95	–	2.90	7985	7402	625	21.0
Hawaii	46.20	6.40	45.90	–	1.50	8160	7538	687	20.3
Java	46.03	6.56	45.55	0.18	1.68	8681	8043	651	20.1
Mexico	47.30	6.08	35.30	–	11.32	9140	8548	667	19.4
Peru	49.00	5.89	43.36	–	1.75	8380	7807	699	20.5
Puerto Rico	44.21	6.31	47.72	0.41	1.35	8386	7773	625	20.5

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Attachment 3-17. Composition and analysis of average municipal waste[6]

Component	Percent of all refuse by weight	Moisture (percent by weight)	Analysis (percent dry weight)							Calorific value (Btu/lb)
			Volatile matter	Carbon	Hydrogen	Oxygen	Nitrogen	Sulfur	Noncombustibles[b]	
					Rubbish, 64%					
Paper	42.0	10.2	84.6	43.4	5.8	44.3	0.3	0.20	6.0	7572
Wood	2.4	20.0	84.9	50.5	6.0	42.4	0.2	0.05	1.0	8613
Grass	4.0	65.0	—	43.3	6.0	41.7	2.2	0.05	6.8	7693
Brush	1.5	40.0	—	42.5	5.9	41.2	2.0	0.05	8.3	7900
Greens	1.5	62.0	70.3	40.3	5.6	39.0	2.0	0.05	13.0	7077
Leaves	5.0	50.0	—	40.5	6.0	45.1	0.2	0.05	8.2	7096
Leather	0.3	10.0	76.2	60.0	8.0	11.5	10.0	0.40	10.1	8850
Rubber	0.6	1.2	85.0	77.7	10.4	—	—	2.0	10.0	11330
Plastics	0.7	2.0	—	60.0	7.2	22.6	—	—	10.2	14368
Oils, paints	0.8	0.0	—	66.9	9.7	5.2	2.0	—	16.3	13400
Linoleum	0.1	2.1	65.8	48.1	5.3	18.7	0.1	0.40	27.4	8310
Rags	0.6	10.0	93.6	55.0	6.6	31.2	4.6	0.13	2.5	7652
Street sweepings	3.0	20.0	67.4	34.7	4.8	35.2	0.1	0.20	25.0	6000
Dirt	1.0	3.2	21.2	20.6	2.6	4.0	0.5	0.01	72.3	3790
Unclassified	0.5	4.0	—	16.6	2.5	18.4	0.05	0.05	62.5	3000
					Food wastes, 12%					
Garbage	10.0	72.0	53.3	45.0	6.4	28.8	3.3	0.52	16.0	8484
Fats	2.0	0.0	—	76.7	12.1	11.2	0	0	0	16700
					Noncombustibles, 24%					
Metals	8.0	3.0	0.5	0.8	0.04	0.2	—	—	99.0	124
Glass & ceramics	6.0	2.0	0.4	0.6	0.03	0.1	—	—	99.3	65
Ashes	10.0	10.0	3.0	28.0	0.5	0.8	—	0.5	70.2	4172
					Composite refuse, as received					
All refuse	100	20.7	—	28.0	3.5	22.4	0.33	0.16	24.9	6203

Chapter 4

Combustion System Design

INTRODUCTION

Combustion systems are normally designed for the conversion of fossil fuels or other combustible substances to forms of energy more suitable for a particular end use and for the accomplishment of this conversion at the lowest possible cost. Such systems are many and varied, inlcuding steam electric power, plants, industrial boilers for process steam and by-product electric power, recovery boilers in paper making, and dryers which use gaseous combustion products for drying veneer and agricultural crops, to name just a few. Combustion can be used for air pollution abatement, through the use of direct flame and catalytic fume incinerators. Incineration of solid wastes and wood wastes is a combustion application where waste disposal has been the primary intent, with energy utilization a secondary cosideration, at least in the past.

The design of a combustion system includes the selection of a fuel and the hardware in which the energy conversion is to be carried out for the particular application. Many factors enter into the choice of the fuel, not the least of which is its availability. The fuel, along with the method of energy utilization will then influence the type of hardware to be employed. The design process is a complex one, involving thermodynamics, fluid mechanics, heat transfer, automatic control theory, and economic considertion. Thermodynamic prinicples govern the basic energy release and utilization potential for each part as well as the system as a whole. Fluid mechanics will govern the fuel and gas flows which the system needs to handle in its varous parts. Fans must be sized to overcome the resistance of gas flows at the operating temperatures and pressures. Flow resistance arises from the dissipation by turbulence, in addition to the fluid friction at physical boundaries. such as walls of ducts, furnaces, heat transfer surfaces, and air quality control equipment. All these equipment pieces must be integrated to produce a system of the most economic configuration within the imposed restraints of the desired energy conversion rate and the environmental quality. The economic consideration includes hardware first-cost, the availability and cost of the fuel, and other system operating and maintenance costs. Careful consideration needs to be given to trade-offs between the capital and the operating costs.

The purpose of this chapter is to develop a design methodology and to illustrate it with numerical examples where possible. We will not be concerned with the detailed design and sizing of the various parts of the combustion installation. The following will be emphasized:

a. The importance of establishing the operating temperatures, and

b. Typical methods of heat utilization.

The nomenclature used throughout the chapter is defined in Attachment 4-2.

Design Methodology

Design methodology is essentialy a process whereby each of the several system components is sized and detailed. Against this backdrop of complexity suggested above, it is reasonable to ask what the flow-diagram of the design process looks like. In general terms, such a flow-diagram might include the following:

a. Determine the quality and load characteristics of energy required.

b. Select the kind of fuel or fuels to be burned. Identify probable sources along with any bulk storage requirements.

c. Determine the combustion air requirements for proper burning of the selected fuel.

d. Estimate the total gas flows generated by the combustion. This determination involves several secondary but important aspects.

   For example:

   1. Thermal efficiency of the unit is determined by minimizing the total of the annual capital and operating cost. Whether or not to include an economizer will be determined from an analysis of the return on the investment.
   2. The amount of fuel to be burned and the combustion products generated are determined from the useful energy to be generated and the efficiency of this conversion process.

e. Determine the required furnace volume and heat transfer areas.

f. Layout the air distribution ducts and the fuel gas breaching. Size the fans and the stack.

g. Identify and design any apparatus required to either prevent or abate air pollution problems.

The manner in which the above tasks are carried out is subject to wide variations from designer to designer. Selected parts of the above-mentioned design process will be considered in the following sections.

Furnace

The combustion chamber is a volume where the fuel and air mixture (in proper proportion) is exposed to an ignition source and burned. The residence time needed to achieve complete oxidation of the fuel depends on the temperature maintained in the combustion chamber, commonly referred to as the furnace. From the temperature effect on the reaction rate (see Chapter 2), we know that the higher the furnace temperature, the faster the oxidation reaction and hence the smaller the furnace would need to be. This size reduction, however, is limited by Charles' Law (see page 2-6).

Adiabatic flame temperatures (see page 2-8), which are the highest temperatures which may be theoretically attained in the furnace, are for most fuels considerably higher than the commonly used furnace materials can tolerate. Uncooled furnace walls constructed of refractory materials normally require the furnace gas temperatures not to exceed 1,800 to 2,200°F. Furnace temperature control, therefore, takes on primary importance. This can be accomplished by:

a. Using excess air in amounts enough to produce desired temperature;
b. Heat removal across heat transfer surfaces; or
c. Some combination of a. and b.

The following example illustrates the furnace temperature calculation procedures.

Example 4.1—Furnace Temperatures

Consider a furnace burning No. 6 fuel oil having a specific gravity of 0.986; a HHV of 18,640 Btu/lb, and an ultimate analysis of 85.7%C, 10.5% H_2, 0.92% O_2, 2.8% S, 0.8% ash, and a net heating value, H, of 17,620 Btu/lb.

Determine:

a. The furnace gas temperature with the following system design alternatives:
  Case 1. Adiabatic combustion (no loss or useful heat transfer) with stoichiometric air;
  Case 2. Stoichiometric air, and 5% energy loss from the furnace to the surroundings.
b. Excess air or heat transfer necessary to achieve 2,200°F furnace temperature:
  Case 3. Excess air but no heat transfer other than 5% energy loss;
  Case 4. Excess air limited to 10%, 5% energy loss, and heat transfer is needed to limit the temperature to 2,200°F.

Solution for Case 1:

First we need to determine the amount of stoichiometric (theoretical) air required for complete combustion. This calculation uses Equation 2.3 (page 2-6).

(4.1)
$$A_t = 11.53\ C + 34.34(H_2 - \frac{O_2}{8}) + 4.29\ S$$

For the No. 6 fuel oil given here, Equation 4.1 is

$$A_t = 11.53(0.857) + 34.34(0.105 - \frac{.009}{8}) + 4.29(.028)$$

$$= 13.57 \frac{\text{lb air}}{\text{lb oil}}$$

When a fuel is burned, mass must be conserved. It is possible then to predict the mass of combustion gas from the air required and the combustible matter actually burned. The mass of flue gas produced is therefore:

(4.2)
$$m_f\ G = (m_f - m_{NC}) + m_f A_t$$

The noncombustibles, m_{NC}, here are either the ash in fuel or the ash together with the unburned combustible in solid form. Gaseous unburned components would remain part of the flue gas. With one pound of fuel as a basis *($m_f = 1$)*, *F* for the No. 6 oil specified here becomes:

$$G = (1 - .008) + (13.57) = 14.56 \frac{lb\ product}{lb\ fuel}$$

The mass of each individual gas in the product can be calculated, and an average or effective specific heat for the mixture can be computed. A value applicable to oil combustion gas temperatures is approximately 0.29 Btu/lb F. With this value, one can estimate the adiabatic flame temperature, t_{ad}, from

(4.3)

$$t_{ad} = \frac{H}{G\ C_p} + t_a$$

where t_a is the combustion air intake temperature. For the oil under consideration, t_{ad} computed using Equation 4.3 with $t_a = 100\,°F$ is

$$t_{ad} = \frac{17{,}620}{14.57(0.29)} + 100 = 4{,}270\,°F$$

Note that this temperature is considerably greater than the furnace materials of construction can tolerate. Therefore, Case 1 is not a viable option.

Solution for Case 2:

A second approach involves predicting the gas temperature when the system has heat transfer losses to the structure and surroundings. Equation 4.3 must be modified by the loss term,, Q_L, to yield the nonadiabatic furnace temperature, t_f, as given by

(4.4)

$$t_f = \frac{H - Q_L}{G\ C_p} + t_a$$

Here, with $Q_L = 0.05\ H$, the furnace temperature is

$$t_f = \frac{H - .05H}{G\ C_p} + t_a = \frac{0.95(17{,}620)}{(14.57)(0.29)} + 100 = 4{,}061\,°F$$

This gas temperature, while lower than that calculated for the adiabatic situation (Case 1), is still too high to be practical.

Solution to Case 3:

The third alternative purposes imposing a limit to the furnace temperature, with a 5% energy loss and no other heat transfer. This can be realized only through the use of excess air. The quantity of excess air needed is determined by a calculation of the mass of combustion product gas, G_f, required to absorb the net heating value of the fuel, H, with the gases leaving the furnace at the specified temperature (2,200 °F). The gas per pound of fuel is

$$G_f = (A_E + G).$$

The applicable energy relationship is given by

$$H = G_f\, C_p(t_f - t_a) + Q_L \tag{4.5}$$

Now if the $t_f = 2{,}200\,°\mathrm{F}$ condition is imposed on the system and assuming $C_p = 0.29$ Btu/lb °F as before G_f can be calculated from

$$G_f = \frac{H - Q_L}{C_p(t_f - t_a)} = \frac{0.95(17{,}620)}{0.29(2{,}200 - 100)} = 27.49\ lbs \tag{4.6}$$

The excess air needed to reduce the temperature is then

$$A_E = G_f - G = 27.49 - 14.57 \simeq 12.92\ \frac{lb\ air}{lb\ fuel}$$

or

$$\frac{A_E}{A_T} = (12.92/13.57) \times 100\% = 95\%$$

This is substantially greater than the excess air normally found necessary for proper combustion of No.6 oil.

Solution to Case 4:

The logical next alternative is to limit the temperature by transferring energy to some useful purpose while limiting the excess air to the amount required for complete combustion. The governing energy equation for this case becomes

$$H = G_f\, C_p(t_f - t_a) + Q_L + Q_u \tag{4.7}$$

Q_u is the energy to be transferred in order to maintain the furnace temperature at t_f. Rearranging Equation 4.7:

(4.8)

$$Q_u = H - Q_L - G_f\, C_p(t_f - t_a)$$

Recalling that Case 4 prescribes 10% excess air

$$G_f = G + A_E \text{ where } A_E = 0.10 \times 13.57 \frac{lb\ air}{lb\ fuel} = 1.36 \frac{lb\ air}{lb\ fuel}$$

and substituting the appropriate numerical values into Equation 4.8 gives

$$Q_u = 17{,}620 - 0.05\ (17{,}620) - (14.57 + 1.36)(.29)(2{,}200 - 100)$$

$$= 16{,}739 - 9{,}701 = 7{,}038 \text{ Btu/lb fuel}$$

Here Q_u represents 39.9% of the net heating value of the fuel. Useful application of this energy obviously depends upon the primary purpose of the combustion system. Steam generation would dictate water walls in the furnace to absorb this energy. Other systems would have to utilize this energy in some other appropriate manner with the heat transfer surface and medium compatible with the intended end use.

Summarizing the design process to this point, the primary alternatives for controlling the furnace temperature to use a great deal of excess air or to use some appropriate heat transfer surface to remove sufficient energy from the combustion gas to effect a control of temperature. The use of excess air alone as a control is wasteful of energy and should be avoided whenever possible. This potentially wasteful aspect is also evident when considering the utilization of the energy remaining in the combustion products after they leave the furnace.

Energy Utilization in Nonfurnace Regions

Further utilization of energy, represented by the elevated temperatures of gases leaving a furnace, has a significant impact on the overall combustion system thermal efficiency, η, defined as:

(4.9)

$$\eta = \frac{Q_s}{Q_H}$$

Q_H is the energy total input to the system given by

(4.10)

$$Q_H = m_f\ HHV$$

and Q_s, the total energy transferred for a useful purpose, is given by

(4.11)
$$Q_s = m_f\ q_s = Q_H - \Sigma\ Q_{loss}$$

where q_s is the useful energy per pound of fuel.

Losses identified earlier were limited to the energy transferred to the structure and the surroundings in the furnace, Q_L. Additional losses occur in the regions through which the gas must flow upon leaving the furnace. A major loss is due to the heat content of flue gases leaving the system. This loss, Q_{fg}, arises from the fact that the flue gas stack temperature, t_{fg}, is higher than ambient and is expressed as

(4.12)
$$Q_{fg} = G_f\ C_p(t_{fg} - t_{amb})$$

Equation 4.12 indicates that Q_{fg} is directly proportional to the total mass of the flue gases, G_f, the specific heat of the gas and the difference between the flue gas and the ambient. Increasing excess air beyond that which is required to insure proper combustion, increases G_f which tends to increase the flue losses. The desirability of reducing the flue gas temperature, t_{fg}, is also apparent. In almost all combustion energy utilization devices, it is impractical to reduce t_{fg} to t_{amb}. Design, material, and economic factors prevent this and, in fact, dictate limits for various cases. Flue gas temperatures in steam boilers are limited to a low of about 250 to 300°F because of the potential dew-point and SO_x – associated corrosion problems which can develop at lower temperatures. Achieving even these flue gas exit temperatures requires considerable energy recovery equipment such as economizers and air preheaters.

The overall energy utilization pattern is summarized in Attachment 4-1, and by the following terms of the enregy balance relationship.

Input: HHV

Losses: $\Sigma Q_{loss} = Q_L + Q_{fg} + Q_v$

Available (utilized) energy: $q_s = Q_u + Q_{NF}$

$q_s = HHV - \Sigma Q_{loss}$

Note that in terms of the net heating value of the fuel, H, the energy balance would become

$$H = HHV - Q_v$$
$$= Q_L + Q_{fg} + q_s$$

The interaction of these several energy quantities is illustrated by the next example which presumes a steam boiler where the fuel is already identified.

Example 4.2—System Thermal Efficiency

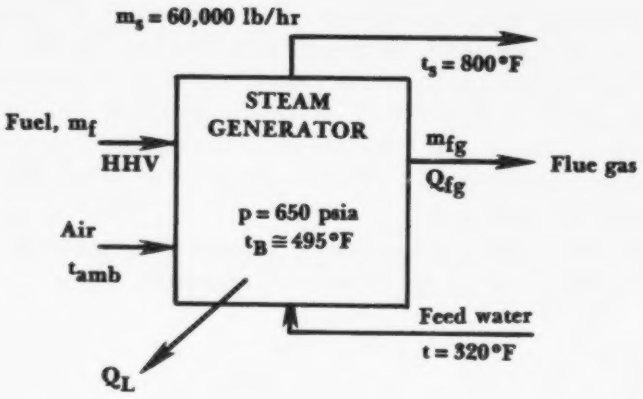
A steam generator is to be designed for firing the No.6 fuel oil of Example 4.1. Its rated output is to be 60,000 lbs/hr output steam at $p = 650$ *psia*, $t = 800\,°F$ with the feedwater at 320 °F.

Determine:

The distribution of the available energy utilization in this steam generator.

Solution:

The design begins with a determination of Q_s for this unit. This is done by accounting for the energy which is added to the working fluid (water) as it passes through the unit.


$m_s = 60{,}000$ lb/hr
$t_s = 800°F$
STEAM GENERATOR
Fuel, m_f
HHV
m_{fg}
Q_{fg}
Flue gas
$p = 650$ psia
$t_B \cong 495°F$
Air
t_{amb}
Feed water
$t = 320°F$
Q_L

Letting m_s represent the steaming rate, Q_s becomes:

$$Q_s = m_s(h_2 - h_1) \qquad (4.13)$$

where h_1 and h_2 are the enthalpies of the entering feedwater and the output steam respectively (obtained from steam tables). For this case

$$Q_s = 60{,}000\ lbs/hr\ (1{,}406.0 - 290.3) = 66.9 \times 10^6\ Btu/hr$$

This is the available useful energy represented by $m_f\,(Q_u + Q_{NF})$. The fuel supply rate needed to provide this energy depends on the overall efficiency, η, which in turn depends on the energy recovery devices incorporated into the design. Again, with information developed Example 4.1,

(4.14) $$q_s = Q_s/m_f = HHV - Q_V - Q_L - Q_{fg} = H - Q_L - Q_{fg}$$

$$q_s = 17{,}620 - Q_L - Q_{fg}$$

Suppose that Q_L can be limited to a maximum of 5% of HHV. Before the remaining loss term, Q_{fg}, can be determined, it is in order to consider some of the temperatures in the system.

Gas leaves the furnace at $t_f = 2{,}200\,°F$, while steam leaves the

Steam superheater at $t_s = 800\,°F$, and the

Steam boiler temperature t_B is $\simeq$ 495 °F (saturation temperature at 650 psia)

The reason for listing these temperatures is to emphasize the limitations imposed by thermodynamic and heat transfer considerations. Energy exchange by heat transfer requires a temperature difference between the energy source and the heated medium. The superheater, if located in the convection zone, might reduce the gas temperature typically from 2,200 °F to say 1,000 °F, which will still allow a 200 °F temperature difference for heat transfer requirements. The boiler operating at the 495 °F boiling temperature can remove enough energy to bring the gas temperature to about 700 °F. These temperatures are practical values, that is, they recognize the need for a finite temperature difference for heat exchange at realistic rates. In any event, temperatures lower than 800 °F for the superheater outlet, and 495 °F for the boiler cannot be realized even with infinite heat transfer areas.

If the steam generator design does not include either an economizer or an air preheater, the gas temperature leaving the system would be approximately 700 °F. For this case the energy loss in the flue gas is given by

$$Q_{fg} = G_f\ C_p(t_{fg} - t_{amb}) = 15.93\ (0.25)(700 - 100)$$

$$= 2{,}390\ \text{Btu/lb fuel}$$

The useful energy per pound of fuel, q_s, is calculated by solving Equation 4.14, noting

$$Q_L = 0.05(18{,}640) = 930\ Btu/lb$$

$$q_s = 17{,}620 - Q_L - Q_{fg} = 17{,}620 - 930 - 2{,}390$$

$$= 14{,}300\ Btu/lb\ oil$$

The efficiency from Equation 4.9, with Q_S and Q_H each based on one pound of fuel is

$$\eta = \frac{14{,}300}{18{,}640} \times 100\% = 76.7\%$$

The fuel firing rate can now be determined noting that the total useful energy, Q_S, is 60.33×10^6 *Btu/hr* and solving for *mf* from Equation 4:14:

$$m_f = \frac{Q_S}{q_S} \quad \frac{66.9 \times 10^6\ Btu/hr}{14{,}300\ \dfrac{Btu}{lb\ oil}} = 4680\ \frac{lb\ oil}{hr}$$

The specific gravity of this No. 6 fuel oil was specified (Example 4.1) to be 0.986, therefore a required fuel flow of approximately 569 gal/hr is indicated.

The efficiency obtainable with a unit which extracts useful energy only in the furnace water walls, superheater, and boiler is not as high as could be realized. Continuing the design process, one would seek means to reduce the flue gas temperature still further, thereby reducing the flue losses and increasing the thermal efficiency. Recall that the feedwater temperature was specified to be 320 °F. This is 175° lower than the boiler temperature of 495 °F. It would therefore appear to be possible to insert a heat exchange surface in the flue gas stream of extract energy by transferring energy to the colder feedwater. Such exchange surface is called the economizer, and, with temperatures as hypothesized here, flue gas temperature could be reduced to 500 °F. With this lower flue gas temperature, the flue losses, Q_{fg}, would be reduced to 1,590 Btu/lb, q_S would increase to 15,000 Btu/lb, and the efficiency would increase to 80.0%.

Continuing the design analysis, one would note the flue gas leaves the economizer at 500 °F and that the ambient air enters at 100 °F. Why not preheat combustion air? A decision to do so or not should, at least in part, be based upon economics. The additional hardware would have a higher first-cost and operating cost, which would have to be balanced against the value of the energy saved. An air preheater could certainly be expected to reduce flue gas temperatures to 350 °F. At 350 °F flue gas temperature the loss Q_{fg} is down to 996 Btu/lb.

Now, from Equation 4.14,

$$q_S = 17{,}620 - 932 - 996 = 15{,}692\ Btu/lb\ fuel$$

and

$$\eta = \frac{15{,}692}{18{,}640} = 84.2\%$$

The fuel firing rate would be

$$m_f = \frac{66.9 \times 10^6\ \dfrac{Btu}{hr}}{15{,}692\ \dfrac{Btu}{lb\ fuel}} = 4260\ \frac{lbs\ fuel}{hr}\ or\ 519\ gal/hr$$

The energy relationships outlined in Examples 4.1 and 4.2 are shown graphically in Attachment 4-1 which pictorially illustrates the effect of greater energy utilization.

An over-all summary of how energy utilization influences the design problem is presented here.

A. Energy utilization determines fuel/air ratio for a given furnace temperature, since more excess air is used with smaller units.

B. Energy utilization involves
   1. Energy absorbed by water walls in the furnace by radiant exchange;
   2. Energy absorbed by superheater;
   3. Energy absorbed by boiler convection surface;
   4. Energy absorbed by the economizer; and
   5. Energy absorbed by air preheater.

C. Energy losses involve
   1. Stack gas losses;
   2. Loss due to heat transfer through structure; and
   3. Loss due to incomplete combustion.

D. A given design is based on a fuel selection as to ultimate analysis, energy content and ash, if any.

System control, to be discussed in a later chapter, must provide for a suitable working range for output and for variations of fuel composition and energy. Drastic changes in any part of a system can substantially alter energy performance or require major modification to avoid loss of performance. Fuel property changes can have some effect since initial design is based on fuel choice.

With the preliminary energy transfer considerations completed as outlined above, various heat transfer calculations are made to design the actual surface configurations. Gas flows, both air and flue gases, together with fluid flow considerations, can be used to establish fan size requirements. A system obviously has many details which have not been displayed here but they are details influenced by the economics of energy utilization.

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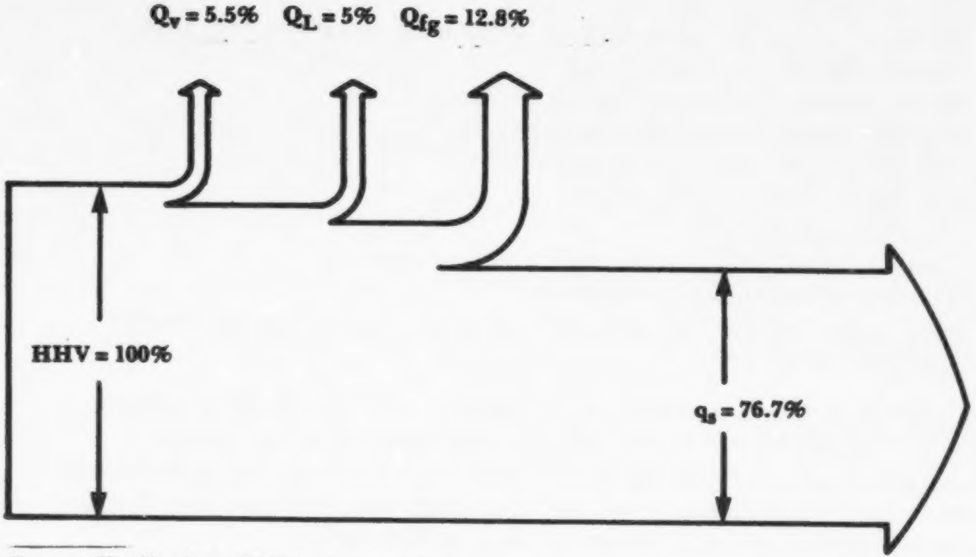
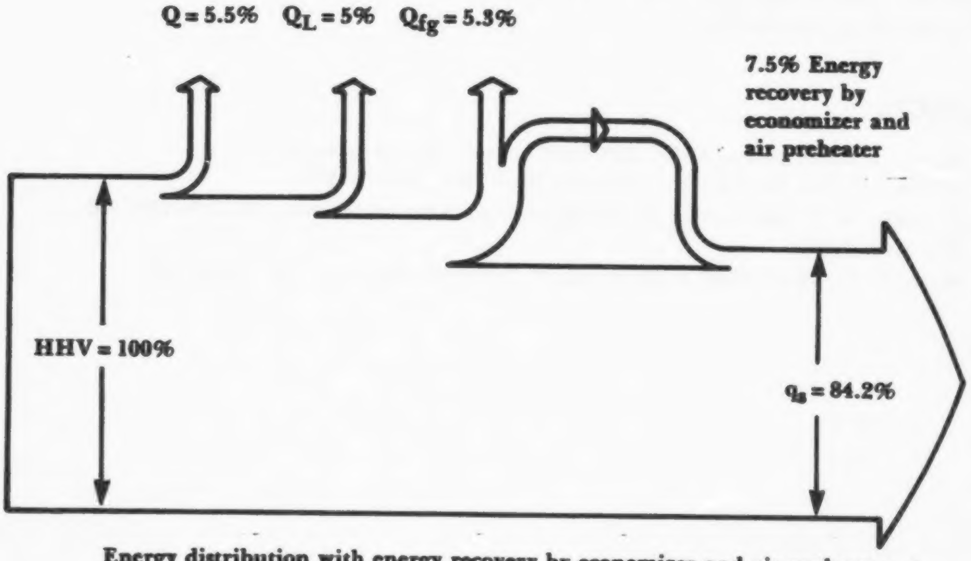
2. Reynolds, W. C. and Perkins, H. C., *Engineering Thermodynamics,* McGraw-Hill, Inc., New York (1977).
3. Morse, F. T., *Power Plant Engineering,* D. Van Nostrand, Inc., New York, 1953.

Attachment 4-1. Energy distribution


$Q_v = 5.5\%$
$Q_L = 5\%$
$Q_{fg} = 12.8\%$
HHV = 100%
$q_s = 76.7\%$

Energy distribution without energy recovery


$Q = 5.5\%$
$Q_L = 5\%$
$Q_{fg} = 5.3\%$
7.5% Energy recovery by economizer and air preheater
HHV = 100%
$q_s = 84.2\%$

Energy distribution with energy recovery by economizer and air preheater

Attachment 4-2. Nomenclature

Symbol	Units	Definition
A_a	lb/lb fuel	Actual combustion air per lb of fuel
A_E	lb/lb fuel	Excess air per lb of fuel
A_t	lb/lb fuel	Theoretical (stoichiometric) air per lb of fuel
C_p	Btu/lb°F	Constant pressure specific heat
G	lb/lb fuel	Flue gas for theoretical combustion per lb of fuel
G_f	lb/lb fuel	Flue gas for combustion with excess air per lb of fuel
h	Btu/lb	Specific enthalpy
H	Btu/lb fuel	Net heating value of fuel
HHV	Btu/lb fuel	Higher heating value
m_f	lbs/hr	Fuel firing rate
m_{NC}	lbs/hr	Noncombustibles in fuel
m_s	lbs/hr	Steaming rate
Q_{fg}	Btu/lb fuel	Energy loss as sensible heat in flue gas
Q_H	Btu/hr	Total energy input
Q_L	Btu/lb fuel	Energy losses s transfer to structure and surroundings
Q_{NF}	Btu/lb fuel	Useful energy per lb of fuel, transferred in non-furnace region
Q_s	Btu/hr	Total energy to useful end purpose
q_s	Btu/lb	Energy to useful purpose per lb of fuel
Q_u	Btu/lb fuel	Useful energy transferred in the furnace per lb of fuel
Q_v	Btu/lb fuel	Energy loss due to latent heat of the water vapor formed by combustion
t_a	°F	Combustion air temperature
t_{ad}	°F	Adiabatic flame temperature
t_{amb}	°F	Ambient air temperature
t_f	°F	Furnace temperature
t_{fg}	°F	Flue gas temperature

Chapter 5

Pollution Emission Calculations

INTRODUCTION

Combustion sources constitute a significant air quality control problem because of the gaseous and particulate emissions which can be produced. With a variety of combustion systems devised for a multitude of end uses, control regulations must be formulated based upon selected standards reasonable for comparison with any given system. Accordingly, emission standards usually establish the maximum allowable limit for the discharge of specific pollutants. These limits are usually based upon volume or mass flows at specified conditions of temperature and pressure. Actual field measurements of gas flow likely would not be made with gas at standard conditions. It is therefore necessary to adjust the observed volume flow to account for difference in pressure and temperature.

Emissions can be measured in terms of the concentration of pollutant per volume or mass of flue (stack) gas; the pollutant mass rate or a rate applicable to a given process. Standards therefore fall into the same three general classifications: concentration standards, pollutant mass-rate standards and process-rate standards. Federal ambient air quality standards are examples of concentration standards where allowable limits are set forth in micrograms per cubic meter at $t_S = 25\,°C$ and $p_S = 760\ mm\ Hg$. Pollutant mass rate standards fix the mass of pollutant which can be emitted per unit time such as lb/hr or Kg/hr. Process-rate standards usually establish the allowable emission in terms of either the input energy or the raw material feed of a process. New source standards for fossil-fired steam power plants are an example of an energy basis standard. Allowable emissions for such operations as acid plants are based upon the mass of acid produced, while a portland cement plant emission standard is in terms of the number of tons of material fed into the kiln. Values for the standards mentioned together with others may be found in Attachment 5-1. Where combustion sources are involved, a standard may include not only the allowable concentration, but may specify the quantity of excess air the system may use while achieving this concentration. The standard for solid waste incinerators of 50 T/day or greater is an example of this type of standard. Such incinerators are limited to particulate emissions not to exceed 0.08 grain/dscf corrected to 12 percent carbon dioxide.

Volume Correction

Since combustion devices always produce flue gas which is at higher temperature and pressure than those of the standards, corrections for the difference must be made. Consider one cubic foot of gas at some specified condition, say 14.7 psia and 70 °F. Does this volume increase or decrease if one raises the gas temperature? Ask a similar question regarding the effect of a pressure increase. What volume would the gas occupy if both pressure and temperature were raised? The answer to these questions can be developed using the equation of state for the gas. A very familiar equation is that for an ideal gas (see Attachment 5.2 for Nomenclature):

$$P_o V_o = MRT_o \tag{5.1}$$

where the subscript *o* denotes some observed condition. Here the mass *M* is fixed and the quantity *R* is a constant, so that upon rearrangement, one may write:

$$\frac{P_o V_o}{T_o} = MR = constant \tag{5.2}$$

Recalling the questions posed above, no gas was added or removed in the speculation of what would happen to the volume as pressure and temperature are changed. Therefore, at some new condition denoted by a subscript *s*, one expects

$$\frac{P_s V_s}{T_s} = MR \tag{5.3}$$

and *MR* can be eliminated by equating 5.2 and 5.3 to give

$$\frac{P_s V_s}{T_s} = \frac{P_o V_o}{T_o} \tag{5.4}$$

Equation 5.4 may be rearranged to give whatever combination may be most useful. For example, suppose the subscript *s* is used to denote standard conditions and the observed conditions are subscripted with an *o*. The observed volume, V_o, measured at temperature, T_o, and pressure, P_o, would occupy volume, V_s, if measured at conditions T_s and P_s as can be seen from a solution of equation 5.4.

$$V_s = V_o \left[\frac{P_o}{P_s}\right] \left[\frac{T_s}{T_o}\right] \quad \text{(Equation 1, Attachment 5-3)}$$

Other parameters may be handled in the same manner. Consider density as an example, noting that the gas law can be modified as follows to explicitly express density

$$P_o = \frac{MRT_o}{V_o} = \varrho_o R T_o \tag{5.5}$$

Rearrangement of equation 5.5 yields:

$$\frac{P_o}{\varrho_o T_o} = R = constant \tag{5.6}$$

Repeating the reasoning employed above for the case of volume, the density of a gas at new conditions denoted by subscript s is:

$$\varrho_s = \varrho_o \left[\frac{P_s}{P_o}\right] \left[\frac{T_o}{T_s}\right] \quad \text{(Equation 3, Attachment 5-3)}$$

Further manipulations of equations can be made to obtain whatever formulation may be useful in a particular case.

As an applied example, consider using the equation of state to help develop a conversion factor with which *ppm* can be reduced to ug/m^3. Beginning with the definition:

(5.7) $$1\ ppm = \frac{moles\ of\ product}{10^6\ moles\ of\ air} = 10^{-6}\ \frac{moles\ of\ product}{moles\ of\ air}.$$

Note that this is basically a volume measure, and that the definition is based on $T = 25\,°C$ and $P = 760\ mm\ Hg$.

Recall here that a mole of any gas will occupy a volume of 22.4 liters when $P = 760\ mm\ Hg$ and $T = 0\,°C$. The definition of *ppm* is based on $T = 25\,°C$: therefore, one must calculate the new volume using Equation 1, Attachment 5-3.

$$V_s = V_o \left[\frac{T_s}{T_o}\right] = 22.4 \left(\frac{273+25}{273}\right) = 24.5\ liter$$

In turn, there are 10^{-3} meter^3/liter and the mass of the moles of product is:

molecular weight × *gm/mole.*

Combining these conversions:

$$1\ ppm = \frac{10^{-6}}{24.5} \times \frac{moles\ product}{liter} \times \frac{MW}{10^{-3}}\ \frac{[gm/mole]}{\left[\frac{m^3}{liter}\right]} =$$

(5.8) $$\frac{10^{-3}}{24.5} MW \left[\frac{gm}{m^3}\right] \times 10^6 \left[\frac{\mu g}{gm}\right] = 40.8\ [MW]\ \frac{\mu g}{m^3}$$

Example: SO_2

$$1\ ppm\ SO_2 = 40.8\,(64) = 2611\ \mu g/m^3$$

Excess Air Corrections

Another type of calculation often necessary involves combustion equipment stack gas samples obtained by Orsat analysis. Before outlining the fundamental basis of corrections here, it would be well to note several aspects of the problem. The stack sampling is directed to determine the pollutants emitted by equipment and compared to standards. The raw gas leaving a combustion device contains certain levels of pollutants, which can be made to appear smaller if the total gas quantity is increased by adding non-pollutant gas to the stream. For example, consider the ideal combustion of carbon monoxide with air

$$CO+\frac{1}{2}O_2+1.88\ N_2\rightarrow CO_2+1.88\ N_2. \tag{5.9}$$

Here, the percentage of CO_2 in the flue gas is:

$$\frac{1}{2.88}=34.8\%\text{ by volume.}$$

Suppose the same mole of CO were burned with 100% excess air? The combustion reaction now is given by:

$$CO+2\left(\frac{1}{2}O_2\right)+2(1.88\ N_2)\rightarrow CO_2+\frac{1}{2}O_2+3.76\ N_2 \tag{5.10}$$

Now the total moles of product is given by:

$$1\ mole\ CO_2+\frac{1}{2}mole\ O_2+3.76\ mole\ N_2=5.26\ moles$$

and

$$CO_2=\frac{1}{5.26}=19.0\%\text{ by volume.}$$

Here the volume fraction of CO_2 was reduced by adding more air, in effect a dilution of the products by additional air.

The original 2.88 moles of flue gas also could have been diluted through the addition of steam, a practice which is fundamentally possible since flue gas temperatures are normally higher than dew-point temperatures. Suppose one added two moles of steam to the flue gas of Equation 5.9:

$$CO_2+1.88\ N_2+2\ moles\ steam \tag{5.11}$$

Now there are 4.88 moles of product and the CO_2 percentage would be

$$CO_2 = \frac{1}{4.88} = 20.5\% \text{ by volume.}$$

Clearly, the volume fraction of any gas present in the flue gas can be reduced by dilution, either by adding air or steam. It is for this reason that combustion equipment emission standards are written with a specified amount of excess air and based on dry flue gas. Flue gases which indicate combustion occurred with excess air different from 50% require correction of observed concentration to that which would have been realized with 50% excess air.

Stack gas measurements are usually made with the Orsat apparatus, an absorption device with separate chambers to remove CO_2, CO, and O_2 from the flue gas in a manner permitting measurement of percentage of each present on a volume basis. The device is designed so that a dry basis measurement is realized. Excess air can be determined from the Orsat readings by computation as follows:

Consider the complete combustion of carbon with air:

(5.12)

$$C + O_2 + 3.76\ N_2 \rightarrow CO_2 + 3.76\ N_2$$

Here the product contains only CO_2 and N_2. With excess air, the reaction becomes:

(5.13)

$$C + (1+a)\ O_2 + (1+a)\ 3.76\ N_2 \rightarrow CO_2 + aO_2 + (1+a)\ 3.76\ N_2$$

where a is the number of moles of excess O_2 in the excess air. By definition, the percent of excess air is:

(5.14)

$$\%EA = \frac{Actual\ Air - Theo\ Air}{Theo\ Air} \times 100\%.$$

The *theo air* is $O_2 + 3.76\ N_2$ from equation 5.12 with the actual air $(1+a)\ O_2 + (1+a)\ 3.76\ N_2$ as given by equation 5.13. Combining equations 5.12, 5.13, and 5.14:

(5.15)

$$\%EA = \frac{aO_2 + a\ 3.76\ N_2}{O_2 + 3.76\ N_2} \times 100\%$$

Equation 5.15 requires knowledge of the excess oxygen, a, in order to compute the excess air. Actually, the Orsat analysis contains the information to accomplish the same result based on knowledge of the product composition alone.

Note that oxygen can only appear in the product if excess air is present, assuming complete combustion. Noting product with a subscript p:

$$C + (1+a)\, O_2 + (1+a)\, 3.76\, N_2 \rightarrow CO_{2p} + O_{2p} + N_{2p} \tag{5.16}$$

where $O_{2p} = aO_2$, the excess oxygen provided, and N_{2p} the nitrogen which was part of the total air supplied. Now the nitrogen present in the product came from the combustion air (unless fuel contained significant nitrogen). Therefore, the actual O_2 supplied can be determined by computing the moles O_2 which were associated with N_{2p}. Assuming air is 20.9% O_2 and 79.1% N_2 by volume, the oxygen supplied is given by:

$$0.264\, N_{2p} = O_2 \text{ supplied} \tag{5.17}$$

$$\text{The theoretical } O_2 \text{ is } 0.264\, N_{2p} - O_{2p} \tag{5.18}$$

$$\text{and the } \%EA = \frac{O_{2p}}{0.264\, N_{2p} - O_{2p}} \times 100\% \tag{5.19}$$

If the combustion produced both CO and CO_2 (case of incomplete combustion), the O_{2p} measured must be reduced by the amount of oxygen which would have combined with CO to form CO_2.

Then:

$$\%EA = \frac{O_{2p} - 0.5CO_p}{0.264\, N_{2p} - (O_{2p} - 0.5CO_p)} \times 100\% \tag{5.20}$$

In each case, the quantity introduced is the percentage of each constituent as measured by the Orsat analyzer.

Example:

Orsat Analysis

$CO_2 = 10\%$
$O_2 = 4\%$
$CO = 1\%$

by difference:

$$N_2 = 100 - (10 + 4 + 1) = 85\%$$

Find % *EA* from equation 5.20:

$$\%EA = \frac{4-0.5\ (1)}{0.264\ (85)-(4-0.5\ (1))} \times 100\% = 18.3\%$$

One caution must be mentioned regarding the CO_2 measurement as determined by an Orsat analyzer. The chemical, caustic potash, employed to absorb CO_2 also absorbs SO_2. Therefore, SO_2 must be measured separately from CO_2 and the percentage SO_2 determined must be subtracted from the observed CO_2 reading. Also, the cuprous chloride solution used to absorb CO also absorbs O_2; therefore, a sample which is not correctly analyzed could erroneously indicate O_2 for CO.

Correction of concentrations where EA is different from 50% is accomplished by adjusting the gas volume to that which would have been present if 50% excess air had been used. Equation 5.20 and correction factors for 50% excess air, 12% CO_2 and 6% O_2 are presented in Attachment 5-4 (Equations 1 through 13). Application of these equations is best illustrated by an example as follows:

Example 5.1

Given: Power plant steam generator data
Stack gas temperature = 756 °R
Pressure = 28.49 in. Hg
Wet gas flow = $Q_o = 367{,}000$ acfm, 6.25% moisture by volume
Apparent molecular weight of gas is 29.29
Orsat analysis is $CO_2 = 10.7\%$; $O_2 = 8.2\%$; $CO = O$
Pollutant mass rate (PMR) is 103 lb/min

With these data, find the following:

A. Pollutant Mass Rate, Tons/day
B. Mass and volume basis concentration
   Standards: $T_s = 530R$; $P_s = 29.92$ *in. Hg*; $\varrho_s = 0.0732\ lb/ft^3$
C. % excess air in effluent
D. Concentrations found in B corrected to 50% EA
E. Concentrations corrected to 12% CO_2
F. Concentrations corrected to 6% O_2

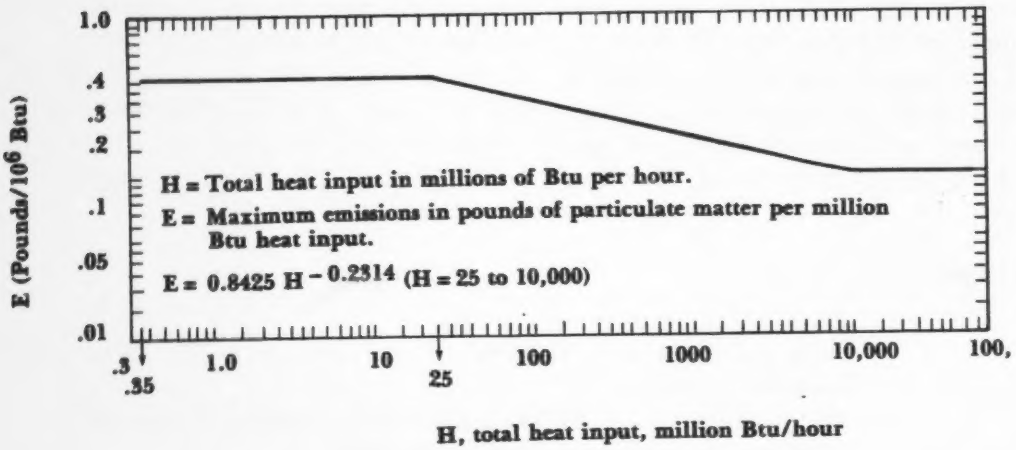


Figure 5.1. Allowable particulate emissions from fuel burning equipment

Solution

A. Pollutant mass rate (PMR), Tons/day:

$$103\ lbs/min \times \frac{60\ min}{hr} \times \frac{24\ hr}{day} \times \frac{Ton}{2000\ lb} = 74.2\ \frac{Tons}{day}$$

B. Concentration-mass and volume basis

$$V_o\ dry = 367{,}000(1 - 0.0625) = 344{,}062\ acfm$$

$$\therefore C_{vo} = \frac{PMR}{V_o} = \frac{103}{344{,}062}$$

Using Equation 2, Attachment 5-3

$$C_{vs} = \frac{103}{344{,}062} \times \frac{29.92}{28.49} \times \frac{756}{530}$$

$$C_{vs} = 4.48 \times 10-4\ \frac{lb}{dscf} \text{ or } 3.14\ \frac{grain}{dscf}$$

$$C_{ms} = C_{vs}\ \frac{lb}{ft^3} \times \frac{ft^3}{0.0732\ lb_m} \times \frac{1000}{1000} = \underline{\underline{\frac{6.12\ lb}{1000\ lb}}}$$

C. % Excess air in effluent using Equation 1, Attachment 5-4.

$$\%EA = \frac{(O_{2p} - 0.5\ CO_p)\ 100}{0.264\ N_{2p} - (O_{2p} - 0.5\ CO_p)}$$

$$= \frac{(8.2 - 0)(100)}{(0.264\ (81.1) - 8.2} = \underline{\underline{61.3\%}}$$

D. Concentration corrected to 50% EA is accomplished using Equations 2 and 3 for the volume basis, 4 and 5 for the mass basis concentrations-all equations taken from Attachment 5-4.

$$F_{50v} = 1 - \left[\frac{1.5\ O_{2p} - 0.133\ N_{2p} - 0.75\ CO_p}{0.21}\right]$$

$$= 1 - \left[\frac{1.5\ (0.082) - 0.133\ (0.811)}{0.21}\right] = \underline{\underline{0.928}}$$

$$C_{50v} = \frac{C_{vs}}{F_{50v}} = \frac{3.14}{0.928} = \underline{\underline{3.38}}\ \frac{grain}{scf}$$

$$F_{50m} = 1 - \frac{29}{M_e}\left[\frac{1.50\ O_{2p} - 0.133\ N_{2p} - 0.75\ CO_p}{0.21}\right] = \underline{\underline{0.930}}$$

$$C_{50m} = \frac{C_{ms}}{F_{50m}} = \frac{6.12}{0.930} = \underline{\underline{6.56}}\ lb/1000\ lb\ dry$$

E. Correction to 12% CO_2 is accomplished with Equations 6 and 7, Attachment 5-3.

$$C_{12v} = \frac{C_{vs}}{F_{12v}} = \frac{C_{vs}}{CO_2/0.12} = \frac{C_v\ (0.12)}{CO_{2p}} = 3.14\left[\frac{0.12}{0.107}\right]$$

$$= \underline{\underline{3.52}}\ \frac{grain}{dscf}$$

F. Correction for 6% O_2 is:

$$F_{6v} = \frac{0.21 - 0.082}{0.15} = 0.85$$

$$C_{6v} = \frac{3.14}{0.85} = \underline{\underline{3.69}}\ \frac{grain}{dscf}$$

Example 5.1 clearly illustrates how one applies corrections for temperature, pressure and excess air. The emissions in this sample were expressed as a concentration given a PMR and volume flow rate.

Process-Rate Factors

Process rates are normally based on either energy or material input to a process, and Example 5.2 illustrates application of a process-rate standard applied to a combustion source. Figure 5.1 is process rate standard for particulates taken from the State of Virginia air quality control regulations.

Example 5.2

Given: $(PMR)_{part} = 1800\ gm/sec$

Fuel: *coal @ 23 tons/hour, HHV* = 12,500 *Btu/lb*
Proposed abatement uses an electrostatic precipitator with 99% rated collection efficiency.

Determine whether this plant meets the standard imposed by the Virginia code.

Solution:

A. Find the process energy rate, H

$$H = \text{mass of coal} \times \text{energy value per unit mass}$$

$$= 23\frac{ton}{hr} \times 12{,}500\frac{Btu}{lb} \times \frac{2000\ lb}{ton}$$

$$= 575 \times 10^6\ Btu/hr$$

B. Find the allowable emission rate from Figure 1.

From graph @ $H = 575 \times 10^6\ Btu/hr$
$E = 0.19$ pounds/10^6 Btu
or calculate from $E = 0.8425(575)^{-0.2314} = 0.194\frac{lb}{10^6\ Btu}$

C. Now find actual particulate weight rate

$$E_{act} = \frac{1800\ gm/sec \times \frac{lb}{454\ gm} \times 3600\ \frac{\sec}{hr}\ (1 - 0.99)}{575 \times 10^6\ \frac{Btu}{hr}}$$

$$E_{actual} = 0.25\frac{pounds}{10^6\ Btu}$$

$0.25 > 0.19$. Therefore, this unit does not conform.

F-Factors

So far the discussion has been directed to the correction of observed field data to account for temperature, pressure and excess air conditions different from those of a standard. Actual volume flow and gas composition were required input. The Federal Register of October 6, 1975 promulgated the F-factor method for the determination of a pollutant emission rate, E, expressed as lbs/10^6 Btu or g/10^6 kJ

The emission rate E is related to concentration and mass rate. The pollutant mass rate, expressed in terms of volume flow rate and concentration is given by:

$$PMR = C_{vs}\ V_s \tag{5.21}$$

The emission rate, E, in terms of the energy input H is:

$$E = \frac{PMR}{H} = \frac{C_{vs}\ V_s}{H} \tag{5.22}$$

Consider the ratio V_s/H, the ratio of gas volume flow to energy input in terms of basic combustion chemistry. For theoretical combustion, the volume V_s can be predicted by computing the products of combustion realized from the burning of a unit mass of fuel. When excess air is used the volume flow is larger than the theoretical, but only by the volume of excess air. It is possible therefore, to compute the volume flow, V_s, in terms of the theoretical volume (stoichiometric) and an excess air correction. Defining the theoretical volume of combustion gases as V_{st}, the volume V_s is:

(5.23)
$$V_s = \frac{V_{st}}{\left[\dfrac{\textit{excess air}}{\textit{correction}}\right]}$$

and equation 5.22 becomes

(5.24)
$$E = C_{vs} \left[\frac{V_{st}}{H}\right] \left[\frac{1}{\dfrac{\textit{excess air}}{\textit{correction}}}\right].$$

The F-factor is defined as:

(5.25)
$$F_d = \frac{V_{st}}{H}$$

and the excess air correction is given by:

(5.26)
$$\left[\frac{20.9 - O_{2p}}{20.9}\right].$$

Substitution of Equations 5.25 and 5.26 into 5.24 yields:

$$E = C_{vs}\ F_d \left[\frac{20.9}{20.9 - O_{2p}}\right].$$

The terms in Equation 5.27 are C_{vs}, the dry basis concentration corrected to standard conditions; the excess air correction based on the percent O_2 in the sampled gas; and F_d, a factor which can be computed knowing fuel composition. Volume flow and fuel flow measurements are not necessary, thus simplifying the task of emission rate determination. For a fuel of known chemical composition and higher heating value H, the factor F_d is given by:

(5.28)
$$F_d = \frac{[3.64\ H_2 + 1.53\ C + 0.57\ S + 0.14\ N_2 - 0.46\ O_2]}{HHV}\ 10^6 \frac{dscf}{10^6\ Btu}$$

The values for H_2, C, S, N_2, O_2 and the percentages of each element are taken from the ultimate analysis. here F_d is noted as the F-factor when dry O_2 percentage was used as the measure of excess air. Should one choose to use CO_2 as the indicator of excess air, a factor F_c is used where:

(5.29)

$$E = C_{vs}\ F_c \left[\frac{100}{CO_{2p}}\right] \frac{lbs}{10^6\ Btu}$$

and

(5.30)

$$F_c = \frac{[321 \times 10^3]}{HHV}\ C_{vs}\ \frac{dscf}{10^6\ Btu}\ .$$

C_{vs}, as used in Equation 5.29, can be either wet or dry basis depending on whether CO_{2p} is determined on a wet or dry basis.

Calculations of F-factors for various fuels indicate a relatively narrow range of values. For example, F_d values for bituminous coal range from 9750 to 9930 dscf/10^6 Btu. Taking the midpoint value, 9820 dscf/10^6 Btu, this range has a maximum deviation of $\pm 3\%$. Attachment 5-5 is a tabulation of calculated mid-range F-factor values with deviations where applicable.

The F-factor method is based on an assumption of complete combustion. There will be an error if CO or unburned combustible is present when O_2 is the measured excess air indicator. A correction similar to that discussed earlier is appropriate as follows:

(5.31)

$$Excess\ air\ correction = \frac{20.9 - (O_{2p} - 0.5\ CO_p)}{20.9}$$

and Equation 5.27 becomes:

(5.32)

$$E = C_{vs}\ F_d \left[\frac{20.9}{20.9 - (O_{2p} - 0.5\ CO_p)}\right].$$

Loss of combustible (unburned carbon in coal ash for example) represents a reduction of actual input energy. F-factor assumes all energy released and since E is proportional to $1/HHV$, calculated E is smaller than the actual. Removal of CO_2 by wet scrubbing also introduces errors where F_c or F_d is the factor employed. Accuracy of the Orsat analysis is as important to the use of F-factors as were the more involved computations discussed previously.

Use of Emission Factors

EPA publication AP-42 is a compilation of emission factors which have been gathered from various references. These factors, while quite valuable when calculations of gross inventory for a large number of sources are involved, are not necessarily valid for a specific single source. A selected group of tables for various common combustion systems and fuels is found in Appendix 5.1.

While more precise emission information is needed in order to pinpoint actual emissions, factors such as those presented in AP-42 can be used to form estimates of the control required.

Example 5.3, using Table 1.1.2, Appendix 5.1, factors for uncontrolled bituminous coal combustion, indicates the particulate loading a spreader stoker might produce is thirteen times the coal ash. This factor tells us that a larger number of spreader stoker fired units operating without control would produce on the average, 13 pounds of particulates for each one percent of ash in the coal burned. Any given unit might produce this amount at some operating capacity but not at all operating levels. At light loads, for example, gas flows are reduced compared to design capacity, and particulate entrainment is reduced because of lower gas velocity.

The emission factors are essentially process emission rate values expressed in terms of mass fired (lbs per ton). These values are convertible to pollutant mass rate, PMR, by knowing the firing rate in lbs per hour.

Example 5.3

If one burns 6 tons/hr of coal with $A = 10\%$ and a heating value HHV of 12,500 Btu/lb in a spreader stoker fired boiler, the uncontrolled emission rate is:

$$E = 13\frac{lb}{ton} \times (10) = 130 \; lbs/ton$$

and the pollutant mass rate is:

$$PMR = 130\frac{lb}{ton} \times 6\frac{ton}{hr} = 780 \; lb/hr \; .$$

Conversion of the emission rate from lbs per ton to lbs per million Btu is as follows:

$$HHV = 12{,}500\frac{Btu}{lb}$$

$$= 12{,}500\frac{Btu}{lb} \times 2{,}000\frac{lb}{ton} = 25 \times 10^6 \; Btu/ton \; .$$

$$\text{Therefore, } E = 130\frac{lb}{ton} \times \frac{1}{25 \times 10^6 \frac{Btu}{ton}} = 5.2 \frac{lbs}{10^6\ Btu} .$$

The degree of control required for a source performance standard of 0.1 lbs/10^6Btu would be determined as follows:

$$\eta = \frac{collected}{Input} \times 100\% = \frac{Input\text{-}Allowable}{Input} \times 100\%$$

$$= \frac{5.2 - 0.1}{5.2} \times 100\% = 98.1\% .$$

This would be an estimate only. More precise emission data for a specific unit would be desirable.

The SO_2 factor is more nearly representative of an actual case since the sulfur in the fuel is measureable. The factor, 38S assumes 4% of the sulfur in the fuel does not appear as SO_2. This difference is greater if the system has a high percentage of unburned fuel in the ash. Where unburned combustible in the ash is a specified value, the SO_2 reduction is calculable, again provided the sulfur appearing as SO_3 can be predicted. The 38S emission factor is a valid first approximation of the uncontrolled SO_2 to be expected. Using the coal in Example 5.3 above with 1.3% sulfur, the following can be seen.

Example 5.4

Compute SO_2 emission per 10^6 Btu for the coal in Example 5.3.

$$E_{SO2} = 38\ (1.3) = 49.4\ \frac{lbs}{ton}$$

$$(PMR)_{SO_2} = 49.4 \frac{lb}{ton} \times 6 \frac{ton}{hr} = 296.4\ \frac{lb}{hr}$$

$$E_{SO_2} = 49.4 \frac{lb}{ton} \times \frac{ton}{25 \times 10^6\ Btu} = 1.98 \frac{lb}{10^6\ Btu}$$

New source standard for SO_2 is 1.2 lb/10^6 Btu which would require

$$\frac{1.98 - 1.2}{1.98} = 39.3\%$$

reduction of SO_2 in the flue gas.

Similar calculations of uncontrolled emissions are possible using factors for HC, NO_X.

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2. Wark, K. and Warner, C.F., *Air Pollution, Its Origin and Control,* Harper & Row Publishers, New York (1976).
3. Perkins, H.C., *Air Pollution,* McGraw-Hill, Inc., New York (1974).
4. Federal Register, Vol. 30, No. 247, Part II (December 23, 1971).
5. Shigehara, R.T., et al., "Summary of F-Factor Methods for Determining Emissions from Combustion Sources," Source Evaluation Society Newsletter, (November 1976).

Attachment 5-1. Typical standards, new source standards—December 23, 1971* (Federal Register Vol. 30, No.427)

1. Fossil-fired steam generators with heat input greater than 250 million Btu/hr.
   A. Particulates: 0.10 lb per 10^6Btu input (0.18 g/10^6 cal) maximum 2 hr average
   B. Opacity: 20% except that 40% shall be permissible for not more than 2 minutes in any hour
   C. Sulfur dioxide and NO_x

	SO_2		NO_x	
	lb/10^6 Btu	kg/10^6kJ	lb/10^6 Btu	kg/10^6kJ
Gaseous Fuel	—	—	0.20	0.09
Liquid Fuel	0.80	0.345	0.30	0.13
Solid Fuel	1.20	0.520	0.70	0.30

2. Solid waste incinerator: charging rate in excess of 50 Tons/day. Particulate emission standard 0.08 grain/dscf (0.18 g/m^3) corrected to 12% CO_2.

3. Portland cement plants: maximum 2 hour average particulate emission of 0.30 lb/ton (0.15 kg/metric ton) and opacity not greater than 20%.

4. Nitric acid plants: maximum 2 hour average nitrogen oxide emission of 3 lb/Ton of acid produced (1.5 kg per metric ton) expressed as nitrogen dioxide.

5. Sulfuric acid plants employing the contact process: maximum 2 hour average emission of SO_2 of 4 lb/Ton of acid produced. Also acid mist standard: maximum 2 hour average emission of 0.15 lb/Ton of acid produced (0.75 kg per metric ton).

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*Note: Standards are revised from time to time.

Attachment 5-2. Nomenclature for equations of Chapter 5

Symbol	
C_m	Concentration, mass basis
C_v	Concentration, volume basis
E	Process emission
EA	Excess air
F	Correction factor; F-factor
H	Energy rate
HHV	Higher heat value
Q	Volume flow rate
M	Mass
MW	Molecular weight
P	Pressure, absolute
PMR	Pollutant mass rate
R	Gas constant
T	Temperature, absolute
V	Volume
ϱ	Density

Subscripts	
e	effluent
p	product
m	mass basis
o	observed conditions
s	standard conditions
v	per-volume basis

Attachment 5-3. Gas volume corrections

Volume

$$V_s = V_o \left[\frac{P_o}{P_s} \right] \left[\frac{T_s}{T_o} \right] \qquad (1)$$

Concentration

$$C_{vs} = C_{vo} \left[\frac{P_s}{P_o} \right] \left[\frac{T_o}{T_s} \right] \qquad (2)$$

Density

$$\varrho_s = \varrho_o \left[\frac{P_s}{P_o} \right] \left[\frac{T_o}{T_s} \right] \qquad (3)$$

Attachment 5-4. Excess air corrections

Determination of Excess Air

$$\%EA = \frac{(O_{2p} - 0.5\ CO_p)}{0.264\ N_{2p} - (O_{2p} - 0.5\ CO_p)} \times 100\% \qquad (1)$$

Factors for Correction to 50% EA

$$F_{50v} = 1 - \left[\frac{1.5O_{2p} - 0.133\ N_{2p} - 0.75\ CO_p}{0.21}\right] \qquad (2)$$

$$C_{50v} = \frac{C_{vs}}{F_{50v}} \qquad (3)$$

$$F_{50m} = 1 - \frac{29}{M_e}\left[\frac{1.5O_{2p} - 0.133\ N_{2p} - 0.75\ CO_p}{0.21}\right] \qquad (4)$$

$$C_{50m} = \frac{C_{ms}}{F_{50m}} \qquad (5)$$

Factor For Correction to 12% CO_2

$$F_{12v} = \frac{CO_{2p}}{0.12} \qquad (6)$$

$$C_{12v} = \frac{C_{vs}}{F_{12v}} \qquad (7)$$

$$F_{12m} = 1 - \frac{29}{M_e}\left[1 - \frac{CO_{2p}}{0.12}\right] \qquad (8)$$

$$C_{12m} = \frac{C_{ms}}{F_{12m}} \qquad (9)$$

Factor For Correction to 6% O_2

$$F_{6v} = \frac{0.21 - O_{2p}}{0.15} \tag{10}$$

$$C_{6v} = \frac{C_{vs}}{F_{6v}} \tag{11}$$

$$F_{6m} = 1 - \frac{29}{M_e}\left[\frac{O_{2p} - 0.06}{0.15}\right] \tag{12}$$

$$C_{6m} = \frac{C_{ms}}{F_{6m}} \tag{13}$$

Attachment 5-5. F-Factors for various fuels[a,b]

Fuel Type	F_d dscf/10^6 Btu	F_c scf/10^6 Btu	F_o
Coal			
Anthracite	10140 (2.0)	1980 (4.1)	1.070 (2.9)
Bituminous	9820 (3.1)	1810 (5.9)	1.140 (4.5)
Lignite	9990 (2.2)	1920 (4.6)	1.0761 (2.8)
Oil	9220 (3.0)	1430 (5.1)	1.3461 (4.1)
Gas			
Natural	8740 (2.2)	1040 (3.9)	1.79 (2.9)
Propane	8740 (2.2)	1200 (1.0)	1.51 (1.2)
Butane	8740 (2.2)	1260 (1.0)	1.479 (0.9)
Wood	9280 (1.9)	1840 (5.0)	1.05 (3.4)
Wood Bark	9640 (4.1)	1860 (3.6)	1.056 (3.9)
Paper and Wood Wastes	9260 (3.6)	1870 (3.3)	1.046 (4.6)
Lawn and Garden Wastes	9590 (5.0)	1840 (3.0)	1.088 (2.4)
Plastics			
Polyethylene	9173	1380	1.394
Polystyrene	9860	1700	1.213
Polyurethane	10010	1810	1.157
Polyvinyl Chloride	9120	1480	1.286
Garbage	9640 (4.0)	1790 (7.9)	1.110 (5.6)

[a] Numbers in parentheses are maximum deviations (%) from the midpoint F-Factors.

[b] To convert to metric system, multiply the above values by 1.123×10^{-4} to obtain scm/10^6 cal.

Source: R.T. Shigehara et al., "Summary of F-Factor Methods for Determining Emissions from Combustion Sources," Source Evaluation Society Newsletter, Vol. 1, No. 4, November 1976.

Appendix 5-1

(The following pages 5-23 through 5-70 are exerpts from AP-42 which relate to combustion sources)

COMPILATION
OF
AIR POLLUTANT EMISION FACTORS

Third Edition
(Including Supplements 1-7)

U.S. Environmental Protection Agency
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1977

This report is published by the Environmental Protection Agency to report information of general interest in the field of air pollution. Copies are available free of charge to Federal employees, current contractors and grantees, and nonprofit organizations—as supplies permit—from the Library Services Office, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. This document is also available to the public for sale through the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C.

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1. EXTERNAL COMBUSTION SOURCES

External combustion sources include steam-electric generating plants, industrial boilers, commercial and institutional boilers, and commercial and domestic combustion units. Coal, fuel oil, and natural gas are the major fossil fuels used by these sources. Other fuels used in relatively small quantities are liquefied petroleum gas, wood, coke, refinery gas, blast furnace gas, and other waste- or by-product fuels. Coal, oil, and natural gas currently supply about 95 percent of the total thermal energy consumed in the United States. In 1970 over 500 million tons (454 x 10^6 MT) of coal, 623 million barrels (99 x 10^9 liters) of distillate fuel oil, 715 million barrels (114 x 10^9 liters) of residual fuel oil, and 22 trillion cubic feet (623 x 10^{12} liters) of natural gas were consumed in the United States.[1]

Power generation, process heating, and space heating are some of the largest fuel-combustion sources of sulfur oxides, nitrogen oxides, and particulate emissions. The following sections present emission factor data for the major fossil fuels – coal, fuel oil, and natural gas – as well as for liquefied petroleum gas and wood waste combustion in boilers.

REFERENCE

1. Ackerson, D.H. Nationwide Inventory of Air Pollutant Emissions. Unpublished report. Office of Air and Water Programs, Environmental Protection Agency, Research Triangle Park, N.C. May 1971.

1.1 BITUMINOUS COAL COMBUSTION

Revised by Robert Rosensteel
and Thomas Lahre

1.1.1 General

Coal, the most abundant fossil fuel in the United States, is burned in a wide variety of furnaces to produce heat and steam. Coal-fired furnaces range in size from small handfired units with capacities of 10 to 20 pounds (4.5 to 9 kilograms) of coal per hour to large pulverized-coal-fired units, which may burn 300 to 400 tons (275 to 360 MT) of coal per hour.

Although predominantly carbon, coal contains many compounds in varying amounts. The exact nature and quantity of these compounds are determined by the location of the mine producing the coal and will usually affect the final use of the coal.

1.1.2 Emissions and Controls

1.1.2.1 Particulates[1] - Particulates emitted from coal combustion consist primarily of carbon, silica, alumina, and iron oxide in the fly-ash. The quantity of atmospheric particulate emissions is dependent upon the type of combustion unit in which the coal is burned, the ash content of the coal, and the type of control equipment used.

Table 1.1-1 gives the range of collection efficiencies for common types of fly-ash control equipment. Particulate emission factors expressed as pounds of particulate per ton of coal burned are presented in Table 1.1-2.

1.1.2.2 Sulfur Oxides[11] - Factors for uncontrolled sulfur oxides emission are shown in Table 1-2 along with factors for other gases emitted. The emission factor for sulfur oxides indicates a conversion of 95 percent of the available sulfur to sulfur oxide. The balance of the sulfur is emitted in the fly-ash or combines with the slag or ash in the furnace and is removed with them.[1] Increased attention has been given to the control of sulfur oxide emissions from the combustion of coal. The use of low-sulfur coal has been recommended in many areas; where low-sulfur coal is not available, other methods in which the focus is on the removal of sulfur oxide from the flue gas before it enters the atmosphere must be given consideration.

A number of flue-gas desulfurization processes have been evaluated; effective methods are undergoing full-scale operation. Processes included in this category are: limestone-dolomite injection, limestone wet scrubbing, catalytic oxidation, magnesium oxide scrubbing, and the Wellman-Lord process. Detailed discussion of various flue-gas desulfurization processes may be found in the literature.[12,13]

1.1.2.3. Nitrogen Oxides[1,5] - Emissions of oxides of nitrogen result not only from the high temperature reaction of atmospheric nitrogen and oxygen in the combustion zone, but also from the partial combustion of nitrogenous compounds contained in the fuel. The important factors that affect NO_x production are: flame and furnace temperature, residence time of combustion gases at the flame temperature, rate of cooling of the gases, and amount of excess air present in the flame. Discussions of the mechanisms involved are contained in the indicated references.

1.1.2.4 Other Gases - The efficiency of combustion primarily determines the carbon monoxide and hydrocarbon content of the gases emitted from bituminous coal combustion. Successful combustion that results in a low level of carbon monoxide and organic emissions requires a high degree of turbulence, a high temperature, and sufficient time for the combustion reaction to take place. Thus, careful control of excess air rates, the use of high combustion temperature, and provision for intimate fuel-air contact will minimize these emissions.

Factors for these gaseous emissions are also presented in Table 1.1-2. The size range in Btu per hour for the various types of furnaces as shown in Table 1.1-2 is only provided as a guide in selecting the proper factor and is not meant to distinguish clearly between furnace applications.

TABLE 1.1-1. RANGE OF COLLECTION EFFICIENCIES FOR COMMON TYPES OF FLY-ASH CONTROL EQUIPMENT[a]

Type of furnace	Range of collection efficiencies, %			
	Electrostatic precipitator	High-efficiency cyclone	Low-resistance cyclone	Settling chamber expanded chimney bases
Cyclone furnace	65 to 99.5[b]	30 to 40	20 to 30	10[b]
Pulverized unit	80 to 99.5[b]	65 to 75	40 to 60	20[b]
Spreader stoker	99.5[b]	85 to 90	70 to 80	20 to 30
Other stokers	99.5[b]	90 to 95	75 to 85	25 to 50

[a] References 1 and 2.

[b] The maximum efficiency to be expected for this collection device applied to this type source.

Table 1.1-2. EMISSION FACTORS FOR BITUMINOUS COAL COMBUSTION WITHOUT CONTROL EQUIPMENT EMISSION FACTOR RATING: A

Furnace size, 10^6 Btu/hr heat input[a]	Particulates[b]		Sulfur oxides[c]		Carbon monoxide		Hydro-carbons[d]		Nitrogen oxides		Aldehydes	
	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned
Greater than 100[e] (Utility and large industrial boilers)												
Pulverized												
General	16A	8A	38S	19S	1	0.5	0.3	0.15	18	9	0.005	0.0025
Wet bottom	13A[f]	6.5A	38S	19S	1	0.5	0.3	0.15	30	15	0.005	0.0025
Dry bottom	17A	8.5A	38S	19S	1	0.5	0.3	0.15	18	9	0.005	0.0025
Cyclone	2A	1A	38S	19S	1	0.5	0.3	0.15	55	27.5	0.005	0.0025
10 to 100[g] (large commercial and general industrial boilers)												
Spreader stoker[h]	13A[i]	6.5A	38S	19S	2	1	1	0.5	15	7.5	0.005	0.0025
Less than 10[j] (commercial and domestic furnaces)												
Underfeed stoker	2A	1A	38S	19S	10	5	3	1.5	6	3	0.005	0.0025
Hand-fired units	20	10	38S	19S	90	45	20	10	3	1.5	0.005	0.0025

[a] 1 Btu/hr = 0.252 kcal/hr.

[b] The letter A on all units other than hand-fired equipment indicates that the weight percentage of ash in the coal should be multiplied by the value given. Example: If the factor is 16 and the ash content is 10 percent, the particulate emissions before the control equipment would be 10 times 16, or 160 pounds of particulate per ton of coal (10 times 8, or 80 kg of particulates per MT of coal).

[c] S equals the sulfur content (see footnote b above).

[d] Expressed as methane.

[e] References 1 and 3 through 7.

[f] Without fly-ash reinjection.

[g] References 1, 4, and 7 through 9.

[h] For all other stokers use 5A for particulate emission factor.

[i] Without fly-ash reinjection. With fly-ash reinjection use 20 A. This value is not an emission factor but represents loading reaching the control equipment.

[j] References 7, 9, and 10.

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1.2 ANTHRACITE COAL COMBUSTION

revised by Tom Lahre

1.2.1 General[1,2]

Anthracite is a high-rank coal having a high fixed-carbon content and low volatile-matter content relative to bituminous coal and lignite. It is also characterized by higher ignition and ash fusion temperatures. Because of its low volatile-matter content and non-clinkering characteristics, anthracite is most commonly fired in medium-sized traveling-grate stokers and small hand-fired units. Some anthracite (occasionally along with petroleum coke) is fired in pulverized-coal-fired boilers. None is fired in spreader stokers. Because of its low sulfur content (typically less than 0.8 percent, by weight) and minimal smoking tendencies, anthracite is considered a desirable fuel where readily available.

In the United States, all anthracite is mined in Northeastern Pennsylvania and consumed primarily in Pennsylvania and several surrounding states. The largest use of anthracite is for space heating; lesser amounts are employed for steam-electric production, coke manufacturing, sintering and pelletizing, and other industrial uses. Anthracite combustion currently represents only a small fraction of the total quantity of coal combusted in the United States.

1.2.2 Emissions and Controls[2-9]

Particulate emissions from anthracite combustion are a function of furnace-firing configuration, firing practices (boiler load, quantity and location of underfire air, sootblowing, flyash reinjection, etc.), as well as of the ash content of the coal. Pulverized-coal-fired boilers emit the highest quantity of particulate per unit of fuel because they fire the anthracite in suspension, which results in a high percentage of ash carryover into the exhaust gases. Traveling-grate stokers and hand-fired units, on the other hand, produce much less particulate per unit of fuel fired. This is because combustion takes place in a quiescent fuel bed and does not result in significant ash carryover into the exhaust gases. In general, particulate emissions from traveling-grate stokers will increase during sootblowing, flyash reinjection, and with higher underfeed air rates through the fuel bed. Higher underfeed air rates, in turn, result from higher grate loadings and the use of forced-draft fans rather than natural draft to supply combustion air. Smoking is rarely a problem because of anthracite's low volatile-matter content.

Limited data are available on the emission of gaseous pollutants from anthracite combustion. It is assumed, based on data derived from bituminous coal combustion, that a large fraction of the fuel sulfur is emitted as sulfur oxides. Moreover, because combustion equipment, excess air rates, combustion temperatures, etc., are similar between anthracite and bituminous coal combustion, nitrogen oxide and carbon monoxide emissions are assumed to be similar, as well. On the other hand, hydrocarbon emissions are expected to be considerably lower because the volatile-matter content of anthracite is significantly less than that of bituminous coal.

Air pollution control of emissions from anthracite combustion has mainly been limited to particulate matter. The most efficient particulate controls–fabric filters, scrubbers, and electrostatic precipitators–have been installed on large pulverized-anthracite-fired boilers. Fabric filters and venturi scrubbers can effect collection efficiencies exceeding 99 percent. Electrostatic precipitators, on the other hand, are typically only 90 to 97 percent efficient due to the characteristic high resistivity of the low-sulfur anthracite flyash. Higher efficiencies can reportedly be achieved using larger precipitators and flue gas conditioning. Mechanical collectors are frequently employed upstream from these devices for large-particle removal.

Traveling-grate stokers are often uncontrolled. Indeed, particulate control has often been considered unnecessary because of anthracite's low smoking tendencies and due to the fact that a significant fraction of the large-sized flyash from stokers is readily collected in flyash hoppers as well as in the breeching and base of the stack. Cyclone collectors have been employed on traveling-grate stokers;

limited information suggests these devices may be up to 75 percent efficient on particulate. Flyash reinjection, frequently employed in traveling-grate stokers to enhance fuel-use efficiency, tends to increase particulate emissions per unit of fuel combusted.

Emission factors for anthracite combustion are presented in Table 1.2-1.

Table 1.2-1. EMISSION FACTORS FOR ANTHRACITE COMBUSTION, BEFORE CONTROLS
EMISSION FACTOR RATING: B

	Emissions[a]									
	Particulate		Sulfur oxides[b]		Hydrocarbons[c]		Carbon monoxide[d]		Nitrogen oxides[e]	
Type of furnace	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Pulverized coal	17A[f]	8.5A[f]	38S	19S	Neg	Neg	1	0.5	18	9
Traveling grate	1A[g]	0.5A[g]	38S	19S	Neg	Neg	1	0.5	10	5
Hand-fired	10[h]	5[h]	38S	19S	2.5	1.25	90	45	3	1.5

[a] All emission factors are per unit of anthracite fired.

[b] These factors are based on the assumption that, as with bituminous coal combustion, most of the fuel sulfur is emitted as sulfur oxides. Limited data in Reference 5 verify this assumption for pulverized-anthracite-fired boilers. Generally most of these emissions are sulfur dioxide; however, approximately 1 to 3 percent are sulfur trioxide.

[c] Hydrocarbon emissions from anthracite combustion are assumed to be lower than from bituminous coal combustion because of anthracite's much lower volatile-matter content. No emissions data are available to verify this assumption.

[d] The carbon monoxide factors for pulverized-anthracite-fired boilers and hand-fired units are from Table 1.1-2 and are based on the similarity between anthracite and bituminous coal combustion. The pulverized-coal-fired boilers factor is substantiated by additional data in Reference 10. The factor for traveling-grate stokers is based on limited information in Reference 8. Carbon monoxide emissions may increase by several orders of magnitude if a boiler is not properly operated or well maintained.

[e] The nitrogen oxide factors for pulverized-anthracite-fired boilers and hand-fired units are assumed to be similar to those for bituminous coal combustion given in Table 1.1-2. The factors for traveling-grate stokers are based on Reference 8.

[f] These factors are based on the similarity between anthracite and bituminous coal combustion and on limited data in Reference 5. Note that all pulverized-anthracite-fired boilers operate in the dry tap or dry bottom mode due to anthracite's characteristically high ash-fusion temperature. The letter A on units other than hand-fired equipment indicates that the weight percentage of ash in the coal should be multiplied by the value given.

[g] Based on information in References 2,4,8, and 9. These factors account for limited fallout that may occur in fallout chambers and stack breeching. Emission factors for individual boilers may vary from 0.5A lb/ton (0.25A kg/MT) to 3A lb/ton (1.5A kg/MT), and as high as 5A lb/ton (2.5A kg/MT) during soot blowing.

[h] Based on limited information in Reference 2.

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1.3 FUEL OIL COMBUSTION

by Tom Lahre

1.3.1 General[1,2]

Fuel oils are broadly classified into two major types: distillate and residual. Distillate oils (fuel oil grades 1 and 2) are used mainly in domestic and small commercial applications in which easy fuel burning is required. Distillates are more volatile and less viscous than residual oils as well as cleaner, having negligible ash and nitrogen contents and usually containing less than 0.3 percent sulfur (by weight). Residual oils (fuel oil grades 4, 5, and 6), on the other hand, are used mainly in utility, industrial, and large commercial applications in which sophisticated combustion equipment can be utilized. (Grade 4 oil is sometimes classified as a distillate; grade 6 is sometimes referred to as Bunker C.) Being more viscous and less volatile than distillate oils, the heavier residual oils (grades 5 and 6) must be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue left over after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Properties of typical fuel oils are given in Appendix A.

1.3.2 Emissions

Emissions from fuel oil combustion are dependent on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Table 1.3-1 presents emission factors for fuel oil combustion in units without control equipment. Note that the emission factors for industrial and commercial boilers are divided into distillate and residual oil categories because the combustion of each produces significantly different emissions of particulates, SO_x, and NO_x. The reader is urged to consult the references cited for a detailed discussion of all of the parameters that affect emissions from oil combustion.

1.3.2.1 Particulates[3-6, 12, 13] – Particulate emissions are most dependent on the grade of fuel fired. The lighter distillate oils result in significantly lower particulate formation than do the heavier residual oils. Among residual oils, grades 4 and 5 usually result in less particulate than does the heavier grade 6.

In boilers firing grade 6, particulate emissions can be described, on the average, as a function of the sulfur content of the oil. As shown in Table 1.3-1 (footnote c), particulate emissions can be reduced considerably when low-sulfur grade 6 oil is fired. This is because low-sulfur grade 6, whether refined from naturally occurring low-sulfur crude oil or desulfurized by one of several processes currently in practice, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur content – all of which result in better atomization and cleaner combustion.

Boiler load can also affect particulate emissions in units firing grade 6 oil. At low load conditions, particulate emissions may be lowered by 30 to 40 percent from utility boilers and by as much as 60 percent from small industrial and commercial units. No significant particulate reductions have been noted at low loads from boilers firing any of the lighter grades, however. At too low a load condition, proper combustion conditions cannot be maintained and particulate emissions may increase drastically. It should be noted, in this regard, that any condition that prevents proper boiler operation can result in excessive particulate formation.

1.3.2.2 Sulfur Oxides (SO_x)[1-5] – Total sulfur oxide emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On the average, more than 95 percent of the fuel sulfur is converted to SO_2, with about 1 to 3 percent further oxidized to SO_3. Sulfur trioxide readily reacts with water vapor (both in the air and in the flue gases) to form a sulfuric acid mist.

Table 1.3-1. EMISSION FACTORS FOR FUEL OIL COMBUSTION
EMISSION FACTOR RATING: A

Pollutant	Type of boiler[a]							
	Power plant		Industrial and commercial				Domestic	
	Residual oil		Residual oil		Distillate oil		Distillate oil	
	$lb/10^3$ gal	$kg/10^3$ liter	$lb/10^3$ gal	$kg/10^3$ liter	$lb/10^3$ gal	$kg/10^3$ liter	$lb/10^3$ gal	$kg/10^3$ liter
Particulate[b]	c	c	c	c	2	0.25	2.5	0.31
Sulfur dioxide[d]	157S	19S	157S	19S	142S	17S	142S	17S
Sulfur trioxide[d]	2S	0.25S	2S	0.25S	2S	0.25S	2S	0.25S
Carbon monoxide[e]	5	0.63	5	0.63	5	0.63	5	0.63
Hydrocarbons (total, as CH_4)[f]	1	0.12	1	0.12	1	0.12	1	0.12
Nitrogen oxides (total, as NO_2)[g]	105(50)[h,i]	12.6(6.25)[h,i]	60[j]	7.5[j]	22	2.8	18	2.3

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[a] Boilers can be classified, roughly, according to their gross (higher) heat input rate, as shown below.

Power plant (utility) boilers: $>250 \times 10^6$ Btu/hr
($>63 \times 10^6$ kg-cal/hr)
Industrial boilers: $>15 \times 10^6$, but $<250 \times 10^6$ Btu/hr
($>3.7 \times 10^6$, but $<63 \times 10^6$ kg-cal/hr)
Commercial boilers: $>0.5 \times 10^6$, but $<15 \times 10^6$ Btu/hr
($>0.13 \times 10^6$, but $<3.7 \times 10^6$ kg-cal/hr)
Domestic (residential) boilers: $<0.5 \times 10^6$ Btu/hr
($<0.13 \times 10^6$ kg-cal/hr)

[b] Based on References 3 through 6. Particulate is defined in this section as that material collected by EPA Method 5 (front half catch)[7].

[c] Particulate emission factors for residual oil combustion are best described, on the average, as a function of fuel oil grade and sulfur content, as shown below.

Grade 6 oil: $lb/10^3$ gal = 10 (S) + 3
[$kg/10^3$ liter = 1.25 (S) + 0.38]
Where: S is the percentage, by weight, of sulfur in the oil
Grade 5 oil: 10 $lb/10^3$ gal (1.25 $kg/10^3$ liter)
Grade 4 oil: 7 $lb/10^3$ gal (0.88 $kg/10^3$ liter)

[d] Based on References 1 through 5. S is the percentage, by weight, of sulfur in the oil.

[e] Based on References 3 through 5 and 8 through 10. Carbon monoxide emissions may increase by a factor of 10 to 100 if a unit is improperly operated or not well maintained.

[f] Based on References 1, 3 through 5, and 10. Hydrocarbon emissions are generally negligible unless unit is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

[g] Based on References 1 through 5 and 8 through 11.

[h] Use 50 $lb/10^3$ gal (6.25 $kg/10^3$ liter) for tangentially fired boilers and 105 $lb/10^3$ gal (12.6 $kg/10^3$ liter) for all others, at full load, and normal (>15 percent) excess air. At reduced loads, NO_x emissions are reduced by 0.5 to 1 percent, on the average, for every percentage reduction in boiler load.

[i] Several combustion modifications can be employed for NO_x reduction: (1) limited excess air firing can reduce NO_x emissions by 5 to 30 percent, (2) staged combustion can reduce NO_x emissions by 20 to 45 percent, and (3) flue gas recirculation can reduce NO_x emissions by 10 to 45 percent. Combinations of the modifications have been employed to reduce NO_x emissions by as much as 60 percent in certain boilers. See section 1.4 for a discussion of these NO_x-reducing techniques.

[j] Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly dependent on the fuel nitrogen content and can be estimated more accurately by the following empirical relationship:

lb $NO_2/10^3$ gal = $22 + 400 (N)^2$
[kg $NO_2/10^3$ liters = $2.75 + 50 (N)^2$]

Where: N is the percentage, by weight, of nitrogen in the oil. Note: For residual oils having high (>0.5%, by weight) nitrogen contents, one should use 120 lb · $NO_2/10^3$ gal (15 kg $NO_2/10^3$ liter) as an emission factor.

1.3.2.3 Nitrogen Oxides (NO_x)[1-6, 8-11, 14] – Two mechanisms form nitrogen oxides: oxidation of fuel-bound nitrogen and thermal fixation of the nitrogen present in combustion air. Fuel NO_x are primarily a function of the nitrogen content of the fuel and the available oxygen (on the average, about 45 percent of the fuel nitrogen is converted to NO_x, but this may vary from 20 to 70 percent). Thermal NO_x, on the other hand, are largely a function of peak flame temperature and available oxygen – factors which are dependent on boiler size, firing configuration, and operating practices.

Fuel nitrogen conversion is the more important NO_x-forming mechanism in boilers firing residual oil. Except in certain large units having unusually high peak flame temperatures, or in units firing a low-nitrogen residual oil, fuel NO_x will generally account for over 50 percent of the total NO_x generated. Thermal fixation, on the other hand, is the predominant NO_x-forming mechanism in units firing distillate oils, primarily because of the negligible nitrogen content in these lighter oils. Because distillate-oil-fired boilers usually have low heat release rates, however, the quantity of thermal NO_x formed in them is less than in larger units.

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. Nitrogen oxides emissions from tangentially (corner) fired boilers are, on the average, only half those of horizontally opposed units. Also important are the firing practices employed during boiler operation. The use of limited excess air firing, flue gas recirculation, staged combustion, or some combination thereof, may result in NO_x reductions ranging from 5 to 60 percent. (See section 1.4 for a discussion of these techniques.) Load reduction can likewise decrease NO_x production. Nitrogen oxides emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, are applicable only in large oil-fired boilers. Limited excess air firing is possible in many small boilers, but the resulting NO_x reductions are not nearly as significant.

1.3.2.4 Other Pollutants[1, 3-5, 8-10, 14] – As a rule, only minor amounts of hydrocarbons and carbon monoxide will be produced during fuel oil combustion. If a unit is operated improperly or not maintained, however, the resulting concentrations of these pollutants may increase bv several orders of magnitude. This is most likely to be the case with small, often unattended units.

1.3.3 Controls

Various control devices and/or techniques may be employed on oil-fired boilers depending on the type of boiler and the pollutant being controlled. All such controls may be classified into three categories: boiler modification, fuel substitution, and flue gas cleaning.

1.3.3.1 Boiler Modification[1-4, 8, 9, 13, 14] – Boiler modification includes any physical change in the boiler apparatus itself or in the operation thereof. Maintenance of the burner system, for example, is important to assure proper atomization and subsequent minimization of any unburned combustibles. Periodic tuning is important in small units to maximize operating efficiency and minimize pollutant emissions, particularly smoke and CO. Combustion modifications such as limited excess air firing, flue gas recirculation, staged combustion, and reduced load operation all result in lowered NO_x emissions in large facilities. (See Table 1.3-1 for specific reductions possible through these combustion modifications.)

1.3.3.2 Fuel Substitution[3-5, 12] – Fuel substitution, that is, the firing of "cleaner" fuel oils, can substantially reduce emissions of a number of pollutants. Lower sulfur oils, for instance, will reduce SO_x emissions in all boilers regardless of size or type of unit or grade of oil fired. Particulates will generally be reduced when a better grade of oil is fired. Nitrogen oxide emissions will be reduced by switching to either a distillate oil or a residual oil containing less nitrogen. The practice of fuel substitution, however, may be limited by the ability of a given operation to fire a better grade of oil as well as the cost and availability thereof.

1.3.3.3 Flue Gas Cleaning[6, 15-21] – Flue gas cleaning equipment is generally only employed on large oil-fired boilers. Mechanical collectors, a prevalent type of control device, are primarily useful in controlling particulates generated during soot blowing, during upset conditions, or when a very dirty, heavy oil is fired. During these situations, high efficiency cyclonic collectors can effect up to 85 percent control of particulate. Under normal firing conditions, however, or when a clean oil is combusted, cyclonic collectors will not be nearly as effective.

Electrostatic precipitators are commonly found in power plants that at one time fired coal. Precipitators that were designed for coal flyash provide only 40 to 60 percent control of oil-fired particulate. Collection efficiencies of up to 90 percent, however, have been reported for new or rebuilt devices that were specifically designed for oil-firing units.

Scrubbing systems have been installed on oil-fired boilers, especially of late, to control both sulfur oxides and particulate. These systems can achieve SO_2 removal efficiencies of up to 90 to 95 percent and provide particulate control efficiencies on the order of 50 to 60 percent. The reader should consult References 20 and 21 for details on the numerous types of flue gas desulfurization systems currently available or under development.

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Revised by Thomas Lahre

1.4 NATURAL GAS COMBUSTION

1.4.1 General [1,2]

Natural gas has become one of the major fuels used throughout the country. It is used mainly for power generation, for industrial process steam and heat production, and for domestic and commercial space heating. The primary component of natural gas is methane, although varying amounts of ethane and smaller amounts of nitrogen, helium, and carbon dioxide are also present. The average gross heating value of natural gas is approximately 1050 Btu/stdft^3 (9350 kcal/Nm^3), varying generally between 1000 and 1100 Btu/stdft^3 (8900 to 9800 kcal/Nm^3).

Because natural gas in its original state is a gaseous, homogenous fluid, its combustion is simple and can be precisely controlled. Common excess air rates range from 10 to 15 percent; however, some large units operate at excess air rates as low as 5 percent to maximize efficiency and minimize nitrogen oxide (NO_x) emissions.

1.4.2 Emissions and Controls [3-16]

Even though natural gas is considered to be a relatively clean fuel, some emissions can occur from the combustion reaction. For example, improper operating conditions, including poor mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide, and hydrocarbons to be produced. Moreover, because a sulfur-containing mercaptan is added to natural gas for detection purposes, small amounts of sulfur oxides will also be produced in the combustion process.

Nitrogen oxides are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions are a function of the temperature in the combustion chamber and the rate of cooling of the combustion products. Emission levels generally vary considerably with the type and size of unit and are also a function of loading.

In some large boilers, several operating modifications have been employed for NO_x control. Staged combustion, for example, including off-stoichiometric firing and/or two-stage combustion, can reduce NO_x emissions by 30 to 70 percent. In off-stoichiometric firing, also called "biased firing," some burners are operated fuel-rich, some fuel-lean, while others may supply air only. In two-staged combustion, the burners are operated fuel-rich (by introducing only 80 to 95 percent stoichiometric air) with combustion being completed by air injected above the flame zone through second-stage "NO-ports." In staged combustion, NO_x emissions are reduced because the bulk of combustion occurs under fuel-rich, reducing conditions.

Other NO_x-reducing modifications include low excess air firing and flue gas recirculation. In low excess air firing, excess air levels are kept as low as possible without producing unacceptable levels of unburned combustibles (carbon monoxide, hydrocarbons, and smoke) and/or other operational problems. This technique can reduce NO_x emissions by 10 to 30 percent primarily because of the lack of availability of oxygen during combustion. Flue gas recirculation into the primary combustion zone, because the flue gas is relatively cool and oxygen deficient, can also lower NO_x emissions by 20 to 60 percent depending on the amount of gas recirculated. At present only a few systems have this capability, however.

Combinations of the above combustion modifications may also be employed to further reduce NO_x emissions. In some boilers, for instance, NO_x reductions as high as 70 to 90 percent have been produced as a result of employing several of these techniques simultaneously. In general, however, because the net effect of any of these combinations varies greatly, it is difficult to predict what the overall reductions will be in any given unit.

Emission factors for natural gas combustion are presented in Table 1.4-1. Flue gas cleaning equipment has not been utilized to control emissions from natural gas combustion equipment.

Table 1.4-1. EMISSION FACTORS FOR NATURAL-GAS COMBUSTION
EMISSION FACTOR RATING: A

Pollutant	Type of unit					
	Power plant		Industrial process boiler		Domestic and commercial heating	
	lb/10^6 ft^3	kg/10^6 m^3	lb/10^6 ft^3	kg/10^6 m^3	lb/10^6 ft^3	kg/10^6 m^3
Particulates[a]	5-15	80-240	5-15	80-240	5-15	80-240
Sulfur oxides (SO_2)[b]	0.6	9.6	0.6	9.6	0.6	9.6
Carbon monoxide[c]	17	272	17	272	20	320
Hydrocarbons (as CH_4)[d]	1	16	3	48	8	128
Nitrogen oxides (NO_2)[e]	700[f-h]	11,200[f-h]	(120-230)[i]	(1920-3680)[i]	(80-120)[j]	(1280-1920)[j]

[a] References 4,7,8,12.

[b] Reference 4 (based on an average sulfur content of natural gas of 2000 gr/10^6 $stdft^3$ (4600 g/10^6 $\underline{N}m^3$).

[c] References 5, 8-12.

[d] References 8, 9, 12.

[e] References 3-9, 12-16.

[f] Use 300 lb/10^6 $stdft^3$ (4800 kg/10^6 $\underline{N}m^3$) for tangentially fired units.

[g] At reduced loads, multiply this factor by the load reduction coefficient given in Figure 1.4-1.

[h] See text for potential NO_x reductions due to combustion modifications. Note that the NO_x reduction from these modifications will also occur at reduced load conditions.

[i] This represents a typical range for many industrial boilers. For large industrial units (> 100 MMBtu/hr) use the NO_x factors presented for power plants.

[j] Use 80 (1280) for domestic heating units and 120 (1920) for commercial units.

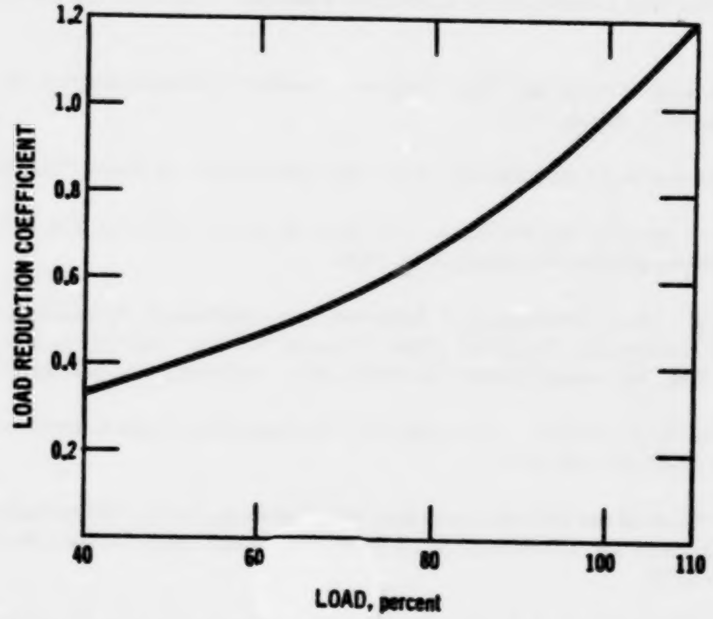

Figure 1.4-1. Load reduction coefficient as function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

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1.5 LIQUEFIED PETROLEUM GAS COMBUSTION

Revised by Thomas Lahre

1.5.1 General[1]

Liquefied petroleum gas, commonly referred to as LPG, consists mainly of butane, propane, or a mixture of the two, and of trace amounts of propylene and butylene. This gas, obtained from oil or gas wells as a by-product of gasoline refining, is sold as a liquid in metal cylinders under pressure and, therefore, is often called bottled gas. LPG is graded according to maximum vapor pressure with Grade A being predominantly butane, Grade F being predominantly propane, and Grades B through E consisting of varying mixtures of butane and propane. The heating value of LPG ranges from 97,400 Btu/gallon (6,480 kcal/liter) for Grade A to 90,500 Btu/gallon (6,030 kcal/liter) for Grade F. The largest market for LPG is the domestic-commercial market, followed by the chemical industry and the internal combustion engine.

1.5.2 Emissions[1]

LPG is considered a "clean" fuel because it does not produce visible emissions. Gaseous pollutants such as carbon monoxide, hydrocarbons, and nitrogen oxides do occur, however. The most significant factors affecting these emissions are the burner design, adjustment, and venting.[2] Improper design, blocking and clogging of the flue vent, and lack of combustion air result in improper combustion that causes the emission of aldehydes, carbon monoxide, hydrocarbons, and other organics. Nitrogen oxide emissions are a function of a number of variables including temperature, excess air, and residence time in the combustion zone. The amount of sulfur dioxide emitted is directly proportional to the amount of sulfur in the fuel. Emission factors for LPG combustion are presented in Table 1.5-1.

References for Section 1.5

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Table 1.5-1. EMISSION FACTORS FOR LPG COMBUSTION[a]
EMISSION FACTOR RATING: C

Pollutant	Industrial process furnaces				Domestic and commercial furnaces			
	Butane		Propane		Butane		Propane	
	lb/10^3 gal	kg/10^3 liters	lb/10^3 gal	kg/10^3 liters	lb/10^3 gal	kg/10^3 liters	lb/10^3 gal	kg/10^3 liters
Particulates	1.8	0.22	1.7	0.20	1.9	0.23	1.8	0.22
Sulfur oxides[b]	0.09S	0.01S	0.09S	0.01S	0.09S	0.01S	0.09S	0.01S
Carbon monoxide	1.6	0.19	1.5	0.18	2.0	0.24	1.9	0.23
Hydrocarbons	0.3	0.036	0.3	0.036	0.8	0.096	0.7	0.084
Nitrogen oxides[c]	12.1	1.45	11.2	1.35	(8 to 12)[d]	(1.0 to 1.5)[d]	(7 to 11)[d]	(0.8 to 1.3)[d]

[a] LPG emission factors calculated assuming emissions (excluding sulfur oxides) are the same, on a heat input basis, as for natural gas combustion.

[b] S equals sulfur content expressed in grains per 100 ft^3 gas vapor; e.g., if the sulfur content is 0.16 grain per 100 ft^3 (0.366 g/100 m^3) vapor, the SO_2 emission factor would be 0.09 × 0.16 or 0.014 lb SO_2 per 1000 gallons (0.01 × 0.366 or 0.0018 kg $SO_2/10^3$ liters) butane burned.

[c] Expressed as NO_2.

[d] Use lower value for domestic units and higher value for commercial units.

1.6 WOOD/BARK WASTE COMBUSTION IN BOILERS

Revised by Thomas Lahre

1.6.1 General [1-3]

Today, the burning of wood/bark waste in boilers is largely confined to those industries where it is available as a by-product. It is burned both to recover heat energy and to alleviate a potential solid waste disposal problem. Wood/bark waste may include large pieces such as slabs, logs, and bark strips as well as smaller pieces such as ends, shavings, and sawdust. Heating values for this waste range from 8000 to 9000 Btu/lb, on a dry basis; however, because of typical moisture contents of 40 to 75 percent, the as-fired heating values for many wood/bark waste materials range as low as 4000 to 6000 Btu/lb. Generally, bark is the major type of waste burned in pulp mills; whereas, a variable mixture of wood and bark waste, or wood waste alone, is most frequently burned in the lumber, furniture, and plywood industries.

1.6.2 Firing Practices[1-3]

A variety of boiler firing configurations are utilized for burning wood/bark waste. One common type in smaller operations is the Dutch Oven, or extension type of furnace with a flat grate. In this unit the fuel is fed through the furnace roof and burned in a cone-shaped pile on the grate. In many other, generally larger, operations, more conventional boilers have been modified to burn wood/bark waste. These units may include spreader stokers with traveling grates, vibrating grate stokers, etc., as well as tangentially fired or cyclone fired boilers. Generally, an auxiliary fuel is burned in these units to maintain constant steam when the waste fuel supply fluctuates and/or to provide more steam than is possible from the waste supply alone.

1.6.3 Emissions [1,2,4-8]

The major pollutant of concern from wood/bark boilers is particulate matter although other pollutants, particularly carbon monoxide, may be emitted in significant amounts under poor operating conditions. These emissions depend on a number of variables including (1) the composition of the waste fuel burned, (2) the degree of fly-ash reinjection employed, and (3) furnace design and operating conditions.

The composition of wood/bark waste depends largely on the industry from whence it originates. Pulping operations, for instance, produce great quantities of bark that may contain more than 70 percent moisture (by weight) as well as high levels of sand and other noncombustibles. Because of this, bark boilers in pulp mills may emit considerable amounts of particulate matter to the atmosphere unless they are well controlled. On the other hand, some operations such as furniture manufacture, produce a clean, dry (5 to 50 percent moisture) wood waste that results in relatively few particulate emissions when properly burned. Still other operations, such as sawmills, burn a variable mixture of bark and wood waste that results in particulate emissions somewhere in between these two extremes.

Fly-ash reinjection, which is commonly employed in many larger boilers to improve fuel-use efficiency, has a considerable effect on particulate emissions. Because a fraction of the collected fly-ash is reinjected into the boiler, the dust loading from the furnace, and consequently from the collection device, increases significantly per ton of wood waste burned. It is reported that full reinjection can cause a 10-fold increase in the dust loadings of some systems although increases of 1.2 to 2 times are more typical for boilers employing 50 to 100 percent reinjection. A major factor affecting this dust loading increase is the extent to which the sand and other non-combustibles can be successfully separated from the fly-ash before reinjection to the furnace.

Furnace design and operating conditions are particularly important when burning wood and bark waste. For example, because of the high moisture content in this waste, a larger area of refractory surface should be provided to dry the fuel prior to combustion. In addition, sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the waste. When proper drying conditions do not exist, or when sufficient secondary air is not available, the combustion temperature is lowered, incomplete combustion occurs, and increased particulate, carbon monoxide, and hydrocarbon emissions will result.

Emission factors for wood waste boilers are presented in Table 1.6-1. For boilers where fly-ash reinjection is employed, two factors are shown: the first represents the dust loading reaching the control equipment; the value in parenthesis represents the dust loading after controls assuming about 80 percent control efficiency. All other factors represent uncontrolled emissions.

Table 1.6-1. EMISSION FACTORS FOR WOOD AND BARK WASTE COMBUSTION IN BOILERS
EMISSION FACTOR RATING: B

Pollutant	Emissions	
	lb/ton	kg/MT
Particulates[a]		
Bark[b,c]		
With fly-ash reinjection[d]	75 (15)	37.5 (7.5)
Without fly-ash reinjection	50	25
Wood/bark mixture[b,e]		
With fly-ash reinjection[d]	45 (9)	22.5 (4.5)
Without fly-ash reinjection	30	15
Wood[f,g]	5-15	2.5-7.5
Sulfur oxides (SO_2)[h,i]	1.5	0.75
Carbon monoxide[j]	2-60	1-30
Hydrocarbons[k]	2-70	1-35
Nitrogen oxides (NO_2)[l]	10	5

[a] These emission factors were determined for boilers burning gas or oil as an auxiliary fuel, and it was assumed all particulates resulted from the waste fuel alone. When coal is burned as an auxiliary fuel, the appropriate emission factor from Table 1.1-2 should be used in addition to the above factor.

[b] These factors based on an as-fired moisture content of 50 percent.

[c] References 2, 4, 9.

[d] This factor represents a typical dust loading reaching the control equipment for boilers employing fly-ash reinjection. The value in parenthesis represents emissions after the control equipment assuming an average efficiency of 80 percent.

[e] References 7, 10.

[f] This waste includes clean, dry (5 to 50 percent moisture) sawdust, shavings, ends, etc., and no bark. For well designed and operated boilers use lower value and higher values for others. This factor is expressed on an as-fired moisture content basis assuming no fly-ash reinjection.

[g] References 11-13.

[h] This factor is calculated by material balance assuming a maximum sulfur content of 0.1 percent in the waste. When auxiliary fuels are burned, the appropriate factors from Tables 1.1-2, 1.3-1, or 1.4-1 should be used in addition to determine sulfur oxide emissions.

[i] References 1, 5, 7.

[j] This factor is based on engineering judgment and limited data from references 11 through 13. Use lower values for well designed and operated boilers.

[k] This factor is based on limited data from references 13 through 15. Use lower values for well designed and operated boilers.

[l] Reference 16.

References for Section 1.6

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2. Atmospheric Emissions from the Pulp and Paper Manufacturing Industry. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA-450/1-73-002. September 1973.

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1.7 LIGNITE COMBUSTION

by Thomas Lahre

1.7.1 General[1-4]

Lignite is a geologically young coal whose properties are intermediate to those of bituminous coal and peat. It has a high moisture content (35 to 40 percent, by weight) and a low heating value (6000 to 7500 Btu/lb, wet basis) and is generally only burned close to where it is mined, that is, in the midwestern States centered about North Dakota and in Texas. Although a small amount is used in industrial and domestic situations, lignite is mainly used for steam-electric production in power plants. In the past, lignite was mainly burned in small stokers; today the trend is toward use in much larger pulverized-coal-fired or cyclone-fired boilers.

The major advantage to firing lignite is that, in certain geographical areas, it is plentiful, relatively low in cost, and low in sulfur content (0.4 to 1 percent by weight, wet basis). Disadvantages are that more fuel and larger facilities are necessary to generate each megawatt of power than is the case with bituminous coal. There are several reasons for this. First, the higher moisture content of lignite means that more energy is lost in the gaseous products of combustion, which reduces boiler efficiency. Second, more energy is required to grind lignite to the specified size needed for combustion, especially in pulverized coal-fired units. Third, greater tube spacing and additional soot blowing are required because of the higher ash-fouling tendencies of lignite. Fourth, because of its lower heating value, more fuel must be handled to produce a given amount of power because lignite is not generally cleaned or dried prior to combustion (except for some drying that may occur in the crusher or pulverizer and during subsequent transfer to the burner). Generally, no major problems exist with the handling or combustion of lignite when its unique characteristics are taken into account.

1.7.2 Emissions and Controls[2-8]

The major pollutants of concern when firing lignite, as with any coal, are particulates, sulfur oxides, and nitrogen oxides. Hydrocarbon and carbon monoxide emissions are usually quite low under normal operating conditions.

Particulate emissions appear most dependent on the firing configuration in the boiler. Pulverized-coal-fired units and spreader stokers, which fire all or much of the lignite in suspension, emit the greatest quantity of flyash per unit of fuel burned. Both cyclones, which collect much of the ash as molten slag in the furnace itself, and stokers (other than spreader stokers), which retain a large fraction of the ash in the fuel bed, emit less particulate matter. In general, the higher sodium content of lignite, relative to other coals, lowers particulate emissions by causing much of the resulting flyash to deposit on the boiler tubes. This is especially the case in pulverized-coal-fired units wherein a high fraction of the ash is suspended in the combustion gases and can readily come into contact with the boiler surfaces.

Nitrogen oxides emissions are mainly a function of the boiler firing configuration and excess air. Cyclones produce the highest NO_x levels, primarily because of the high heat-release rates and temperatures reached in the small furnace sections of the boiler. Pulverized-coal-fired boilers produce less NO_x than cyclones because combustion occurs over a larger volume, which results in lower peak flame temperatures. Tangentially fired boilers produce the lowest NO_x levels in this category. Stokers produce the lowest NO_x levels mainly because most existing units are much smaller than the other firing types. In most boilers, regardless of firing configuration, lower excess air during combustion results in lower NO_x emissions.

Sulfur oxide emissions are a function of the alkali (especially sodium) content of the lignite ash. Unlike most fossil fuel combustion, in which over 90 percent of the fuel sulfur is emitted as SO_2, a significant fraction of the sulfur in lignite reacts with the ash components during combustion and is retained in the boiler ash deposits and flyash. Tests have shown that less than 50 percent of the available sulfur may be emitted as SO_2 when a high-sodium lignite is burned, whereas, more than 90 percent may be emitted with low-sodium lignite. As a rough average, about 75 percent of the fuel sulfur will be emitted as SO_2, with the remainder being converted to various sulfate salts.

Air pollution controls on lignite-fired boilers in the United States have mainly been limited to cyclone collectors, which typically achieve 60 to 75 percent collection efficiency on lignite flyash. Electrostatic precipitators, which are widely utilized in Europe on lignitic coals and can effect 99+ percent particulate control, have seen only limited application in the United States to date although their use will probably become widespread on newer units in the future.

Nitrogen oxides reduction (up to 40 percent) has been demonstrated using low excess air firing and staged combustion (see section 1.4 for a discussion of these techniques); it is not yet known, however, whether these techniques can be continuously employed on lignite combustion units without incurring operational problems. Sulfur oxides reduction (up to 50 percent) and some particulate control can be achieved through the use of high sodium lignite. This is not generally considered a desirable practice, however, because of the increased ash fouling that may result.

Emission factors for lignite combustion are presented in Table 1.7-1.

Table 1.7-1. EMISSIONS FROM LIGNITE COMBUSTION WITHOUT CONTROL EQUIPMENT[a]
EMISSION FACTOR RATING: B

Pollutant	Type of boiler							
	Pulverized-coal		Cyclone		Spreaker stoker		Other stokers	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Particulate[b]	7.0A[c]	3.5A[c]	6A	3A	7.0A[d]	3.5A[d]	3.0A	1.5A
Sulfur oxides[e]	30S	15S	30S	15S	30S	15S	30S	15S
Nitrogen oxides[f]	14(8)[g,h]	7(4)[g,h]	17	8.5	6	3	6	3
Hydrocarbons[i]	<1.0	<0.5	<1.0	<0.5	1.0	0.5	1.0	0.5
Carbon monoxide[i]	1.0	0.5	1.0	0.5	2	1	2	1

[a] All emission factors are expressed in terms of pounds of pollutant per ton (kilograms of pollutant per metric ton) of lignite burned, wet basis (35 to 40 percent moisture, by weight).

[b] A is the ash content of the lignite by weight, wet basis. Factors based on References 5 and 6.

[c] This factor is based on data for dry-bottom, pulverized-coal-fired units only. It is expected that this factor would be lower for wet-bottom units.

[d] Limited data preclude any determination of the effect of flyash reinjection. It is expected that particulate emissions would be greater when reinjection is employed.

[e] S is the sulfur content of the lignite by weight, wet basis. For a high sodium-ash lignite ($Na_2O > 8$ percent) use 17S lb/ton (8.5S kg/MT); for a low sodium-ash lignite ($Na_2O < 2$ percent), use 35S lb/ton (17.5S kg/MT). For intermediate sodium-ash lignite, or when the sodium-ash content is unknown, use 30S lb/ton (15S kg/MT)). Factors based on References 2, 5, and 6.

[f] Expressed as NO_2. Factors based on References 2, 3, 5, 7, and 9.

[g] Use 14 lb/ton (7 kg/MT) for front-wall-fired and horizontally opposed wall-fired units and 8 lb/ton (4 kg/MT) for tangentially fired units.

[h] Nitrogen oxide emissions may be reduced by 20 to 40 percent with low excess air firing and/or staged combustion in front-fired and opposed-wall-fired units and cyclones.

[i] These factors are based on the similarity of lignite combustion to bituminous coal combustion and on limited data in Reference 7.

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1.8 BAGASSE COMBUSTION IN SUGAR MILLS

by Tom Lahre

1.8.1 General[1]

Bagasse is the fibrous residue from sugar cane that has been processed in a sugar mill. (See Section 6.12 for a brief general description of sugar cane processing.) It is fired in boilers to eliminate a large solid waste disposal problem and to produce steam and electricity to meet the mill's power requirements. Bagasse represents about 30 percent of the weight of the raw sugar cane. Because of the high moisture content (usually at least 50 percent, by weight) a typical heating value of wet bagasse will range from 3000 to 4000 Btu/lb (1660 to 2220 kcal/kg). Fuel oil may be fired with bagasse when the mill's power requirements cannot be met by burning only bagasse or when bagasse is too wet to support combustion.

The United States sugar industry is located in Florida, Louisiana, Hawaii, Texas, and Puerto Rico. Except in Hawaii, where raw sugar production takes place year round, sugar mills operate seasonally, from 2 to 5 months per year.

Bagasse is commonly fired in boilers employing either a solid hearth or traveling grate. In the former, bagasse is gravity fed through chutes and forms a pile of burning fibers. The burning occurs on the surface of the pile with combustion air supplied through primary and secondary ports located in the furnace walls. This kind of boiler is common in older mills in the sugar cane industry. Newer boilers, on the other hand, may employ traveling-grate stokers. Underfire air is used to suspend the bagasse, and overfired air is supplied to complete combustion. This kind of boiler requires bagasse with a higher percentage of fines, a moisture content not over 50 percent, and more experienced operating personnel.

1.8.2 Emissions and Controls[1]

Particulate is the major pollutant of concern from bagasse boilers. Unless an auxiliary fuel is fired, few sulfur oxides will be emitted because of the low sulfur content (<0.1 percent, by weight) of bagasse. Some nitrogen oxides are emitted, although the quantities appear to be somewhat lower (on an equivalent heat input basis) than are emitted from conventional fossil fuel boilers.

Particulate emissions are reduced by the use of multi-cyclones and wet scrubbers. Multi-cyclones are reportedly 20 to 60 percent efficient on particulate from bagasse boilers, whereas scrubbers (either venturi or the spray impingement type) are usually 90 percent or more efficient. Other types of control equipment have been investigated but have not been found to be practical.

Emission factors for bagasse fired boilers are shown in Table 1.8-1.

Table 1.8-1. EMISSION FACTORS FOR UNCONTROLLED BAGASSE BOILERS
EMISSION FACTOR RATING: C

	Emission factors			
	lb/10^3 lb steam[a]	g/kg steam[a]	lb/ton bagasse[b]	kg/MT bagasse[b]
Particulate[c]	4	4	16	8
Sulfur oxides	d	d	d	d
Nitrogen oxides[e]	0.3	0.3	1.2	0.6

[a] Emission factors are expressed in terms of the amount of steam produced, as most mills do not monitor the amount of bagasse fired. These factors should be applied only to that fraction of steam resulting from bagasse combustion. If a significant amount (>25% of total Btu input) of fuel oil is fired with the bagasse, the appropriate emission factors from Table 1.3-1 should be used to estimate the emission contributions from the fuel oil.

[b] Emissions are expressed in terms of wet bagasse, containing approximately 50 percent moisture, by weight. As a rule of thumb, about 2 pounds (2 kg) of steam are produced from 1 pound (1kg) of wet bagasse.

[c] Multi-cyclones are reportedly 20 to 60 percent efficient on particulate from bagasse boilers. Wet scrubbers are capable of effecting 90 or more percent particulate control. Based on Reference 1.

[d] Sulfur oxide emissions from the firing of bagasse alone would be expected to be negligible as bagasse typically contains less than 0.1 percent sulfur, by weight. If fuel oil is fired with bagasse, the appropriate factors from Table 1.3-1 should be used to estimate sulfur oxide emissions.

[e] Based on Reference 1.

Reference for Section 1.8

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1.9 RESIDENTIAL FIREPLACES

by Tom Lahre

1.9.1 General[1,2]

Fireplaces are utilized mainly in homes, lodges, etc., for supplemental heating and for their aesthetic effect. Wood is most commonly burned in fireplaces; however, coal, compacted wood waste "logs," paper, and rubbish may all be burned at times. Fuel is generally added to the fire by hand on an intermittent basis.

Combustion generally takes place on a raised grate or on the floor of the fireplace. Combustion air is supplied by natural draft, and may be controlled, to some extent, by a damper located in the chimney directly above the firebox. It is common practice for dampers to be left completely open during the fire, affording little control of the amount of air drawn up the chimney.

Most fireplaces heat a room by radiation, with a significant fraction of the heat released during combustion (estimated at greater than 70 percent) lost in the exhaust gases or through the fireplace walls. In addition, as with any fuel-burning, space-heating device, some of the resulting heat energy must go toward warming the air that infiltrates into the residence to make up for the air drawn up the chimney. The net effect is that fireplaces are extremely inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing apreciable radiant heat energy) a net heat loss may occur in a residence due to the use of a fireplace. Fireplace efficiency may be improved by a number of devices that either reduce the excess air rate or transfer some of the heat back into the residence that is normally lost in the exhaust gases or through the fireplace walls.

1.9.2 Emissions[1,2]

The major pollutants of concern from fireplaces are unburnt combustibles–carbon monoxide and smoke. Significant quantities of these pollutants are produced because fireplaces are grossly inefficient combustion devices due to high, uncontrolled excess air rates, low combustion temperatures, and the absence of any sort of secondary combustion. The last of these is especially important when burning wood because of its typically high (80 percent, on a dry weight basis)[3] volatile matter content.

Because most wood contains negligible sulfur, very few sulfur oxides are emitted. Sulfur oxides will be produced, of course, when coal or other sulfur-bearing fuels are burned. Nitrogen oxide emissions from fireplaces are expected to be negligible because of the low combustion temperatures involved.

Emission factors for wood and coal combustion in residential fireplaces are given in Table 1.9-1.

Table 1.9-1. EMISSION FACTORS FOR RESIDENTIAL FIREPLACES
EMISSION FACTOR RATING: C

Pollutant	Wood		Coal[a]	
	lb/ton	kg/MT	lb/ton	kg/MT
Particulate	20[b]	10[b]	30[c]	15[c]
Sulfur oxides	0[d]	0[d]	36S[e]	36S[e]
Nitrogen oxides	1[f]	0.5[f]	3	1.5
Hydrocarbons	5[g]	2.5[g]	20	10
Carbon monoxide	120[h]	60[h]	90	45

[a] All coal emission factors, except particulate, are based on data in Table 1.1-2 of Section 1.1 for hand-fired units.

[b] This includes condensable particulate. Only about 30 percent of this is filterable particulate as determined by EPA Method 5 (front-half catch).[4] Based on limited data from Reference 1.

[c] This includes condensable particulate. About 50 percent of this is filterable particulate as determined by EPA Method 5 (front-half catch).[4] Based on limited data from Reference 1.

[d] Based on negligible sulfur content in most wood.[3]

[e] S is the sulfur content, on a weight percent basis, of the coal.

[f] Based on data in Table 2.3-1 in Section 2.3 for wood waste combustion in conical burners.

[g] Nonmethane volatile hydrocarbons. Based on limited data from Reference 1.

[h] Based on limited data from Reference 1.

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2. SOLID WASTE DISPOSAL

Revised by Robert Rosensteel

As defined in the Solid Waste Disposal Act of 1965, the term "solid waste" means garbage, refuse, and other discarded solid materials, including solid-waste materials resulting from industrial, commercial, and agricultural operations, and from community activities. It includes both combustibles and noncombustibles.

Solid wastes may be classified into four general categories: urban, industrial, mineral, and agricultural. Although urban wastes represent only a relatively small part of the total solid wastes produced, this category has a large potential for air pollution since in heavily populated areas solid waste is often burned to reduce the bulk of material requiring final disposal.[1] The following discussion will be limited to the urban and industrial waste categories.

An average of 5.5 pounds (2.5 kilograms) of urban refuse and garbage is collected per capita per day in the United States.[2] This figure does not include uncollected urban and industrial wastes that are disposed of by other means. Together, uncollected urban and industrial wastes contribute at least 4.5 pounds (2.0 kilograms) per capita per day. The total gives a conservative per capita generation rate of 10 pounds (4.5 kilograms) per day of urban and industrial wastes. Approximately 50 percent of all the urban and industrial waste generated in the United States is burned, using a wide variety of combustion methods with both enclosed and open burning[3]. Atmospheric emissions, both gaseous and particulate, result from refuse disposal operations that use combustion to reduce the quantity of refuse. Emissions from these combustion processes cover a wide range because of their dependence upon the refuse burned, the method of combustion or incineration, and other factors. Because of the large number of variables involved, it is not possible, in general, to delineate when a higher or lower emission factor, or an intermediate value should be used. For this reason, an average emission factor has been presented.

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2.1 REFUSE INCINERATION

Revised by Robert Rosensteel

2.1.1 Process Description[1-4]

The most common types of incinerators consist of a refractory-lined chamber with a grate upon which refuse is burned. In some newer incinerators water-walled furnaces are used. Combustion products are formed by heating and burning of refuse on the grate. In most cases, since insufficient underfire (undergrate) air is provided to enable complete combustion, additional over-fire air is admitted above the burning waste to promote complete gas-phase combustion. In multiple-chamber incinerators, gases from the primary chamber flow to a small secondary mixing chamber where more air is admitted, and more complete oxidation occurs. As much as 300 percent excess air may be supplied in order to promote oxidation of combustibles. Auxiliary burners are sometimes installed in the mixing chamber to increase the combustion temperature. Many small-size incinerators are single-chamber units in which gases are vented from the primary combustion chamber directly into the exhaust stack. Single-chamber incinerators of this type do not meet modern air pollution codes.

2.1.2 Definitions of Incinerator Categories[1]

No exact definitions of incinerator size categories exist, but for this report the following general categories and descriptions have been selected:

1. *Municipal incinerators* – Multiple-chamber units often have capacities greater than 50 tons (45.3 MT) per day and are usually equipped with automatic charging mechanisms, temperature controls, and movable grate systems. Municipal incinerators are also usually equipped with some type of particulate control device, such as a spray chamber or electrostatic precipitator.

2. *Industrial/commercial incinerators* – The capacities of these units cover a wide range, generally between 50 and 4,000 pounds (22.7 and 1,800 kilograms) per hour. Of either single- or multiple-chamber design, these units are often manually charged and intermittently operated. Some industrial incinerators are similar to municipal incinerators in size and design. Better designed emission control systems include gas-fired afterburners or scrubbing, or both.

3. *Trench Incinerators* – A trench incinerator is designed for the combustion of wastes having relatively high heat content and low ash content. The design of the unit is simple: a U-shaped combustion chamber is formed by the sides and bottom of the pit and air is supplied from nozzles along the top of the pit. The nozzles are directed at an angle below the horizontal to provide a curtain of air across the top of the pit and to provide air for combustion in the pit. The trench incinerator is not as efficient for burning wastes as the municipal multiple-chamber unit, except where careful precautions are taken to use it for disposal of low-ash, high-heat-content refuse, and where special attention is paid to proper operation. Low construction and operating costs have resulted in the use of this incinerator to dispose of materials other than those for which it was originally designed. Emission factors for trench incinerators used to burn three such materials[7] are included in Table 2.1-1.

4. *Domestic incinerators* – This category includes incinerators marketed for residential use. Fairly simple in design, they may have single or multiple chambers and usually are equipped with an auxiliary burner to aid combustion.

Table 2.1-1. EMISSION FACTORS FOR REFUSE INCINERATORS WITHOUT CONTROLS[a]
EMISSION FACTOR RATING: A

Incinerator type	Particulates		Sulfur oxides[b]		Carbon monoxide		Hydrocarbons[c]		Nitrogen oxides[d]	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Municipal[e]										
Multiple chamber, uncontrolled	30	15	2.5	1.25	35	17.5	1.5	0.75	3	1.5
With settling chamber and water spray system[f]	14	7	2.5	1.25	35	17.5	1.5	0.75	3	1.5
Industrial/commercial										
Multiple chamber[g]	7	3.5	2.5[h]	1.25	10	5	3	1.5	3	1.5
Single chamber[i]	15	7.5	2.5[h]	1.25	20	10	15	7.5	2	1
Trench[j]										
Wood	13	6.5	0.1[k]	0.05	NA[l]	NA	NA	NA	4	2
Rubber tires	138	69	NA	NA	NA	NA	NA	NA	NA	NA
Municipal refuse	37	18.5	2.5[h]	1.25	NA	NA	NA	NA	NA	NA
Controlled air[m]	1.4	0.7	1.5	0.75	Neg	Neg	Neg	Neg	10	5
Flue-fed single chamber[n]	30	15	0.5	0.25	20	10	15	7.5	3	1.5
Flue-fed (modified)[o,p]	6	3	0.5	0.25	10	5	3	1.5	10	5
Domestic single chamber										
Without primary burner[q]	35	17.5	0.5	0.25	300	150	100	50	1	0.5
With primary burner[r]	7	3.5	0.5	0.25	Neg	Neg	2	1	2	1
Pathological[s]	8	4	Neg	Neg	Neg	Neg	Neg	Neg	3	1.5

[a] Average factors given based on EPA procedures for incinerator stack testing.

[b] Expressed as sulfur dioxide.

[c] Expressed as methane.

[d] Expressed as nitrogen dioxide.

[e] References 5 and 8 through 14.

[f] Most municipal incinerators are equipped with at least this much control: see Table 2.1-2 for appropriate efficiencies for other controls.

[g] References 3, 5, 10, 13, and 15.

[h] Based on municipal incinerator data.

[i] References 3, 5, 10, and 15.

[j] Reference 7.

[k] Based on data for wood combustion in conical burners.

[l] Not available.

[m] Reference 9.

[n] References 3, 10, 11, 13, 15, and 16.

[o] With afterburners and draft controls.

[p] References 3, 11, and 15.

[q] References 5 and 10.

[r] Reference 5.

[s] References 3 and 9.

5. *Flue-fed incinerators* – These units, commonly found in large apartment houses, are characterized by the charging method of dropping refuse down the incinerator flue and into the combustion chamber. Modified flue-fed incinerators utilize afterburners and draft controls to improve combustion efficiency and reduce emissions.

6. *Pathological incinerators* – These are incinerators used to dispose of animal remains and other organic material of high moisture content. Generally, these units are in a size range of 50 to 100 pounds (22.7 to 45.4 kilograms) per hour. Wastes are burned on a hearth in the combustion chamber. The units are equipped with combustion controls and afterburners to ensure good combustion and minimal emissions.

7. *Controlled air incinerators* – These units operate on a controlled combustion principle in which the waste is burned in the absence of sufficient oxygen for complete combustion in the main chamber. This process generates a highly combustible gas mixture that is then burned with excess air in a secondary chamber, resulting in efficient combustion. These units are usually equipped with automatic charging mechanisms and are characterized by the high effluent temperatures reached at the exit of the incinerators.

2.1.3 Emissions and Controls[1]

Operating conditions, refuse composition, and basic incinerator design have a pronounced effect on emissions. The manner in which air is supplied to the combustion chamber or chambers has, among all the parameters, the greatest effect on the quantity of particulate emissions. Air may be introduced from beneath the chamber, from the side, or from the top of the combustion area. As underfire air is increased, an increase in fly-ash emissions occurs. Erratic refuse charging causes a disruption of the combustion bed and a subsequent release of large quantities of particulates. Large quantities of uncombusted particulate matter and carbon monoxide are also emitted for an extended period after charging of batch-fed units because of interruptions in the combustion process. In continuously fed units, furnace particulate emissions are strongly dependent upon grate type. The use of rotary kiln and reciprocating grates results in higher particulate emissions than the use of rocking or traveling grates.[14] Emissions of oxides of sulfur are dependent on the sulfur content of the refuse. Carbon monoxide and unburned hydrocarbon emissions may be significant and are caused by poor combustion resulting from improper incinerator design or operating conditions. Nitrogen oxide emissions increase with an increase in the temperature of the combustion zone, an increase in the residence time in the combustion zone before quenching, and an increase in the excess air rates to the point where dilution cooling overcomes the effect of increased oxygen concentration.[14]

Table 2.1-2 lists the relative collection efficiencies of particulate control equipment used for municipal incinerators. This control equipment has little effect on gaseous emissions. Table 2.1-1 summarizes the uncontrolled emission factors for the various types of incinerators previously discussed.

Table 2.1-2. COLLECTION EFFICIENCIES FOR VARIOUS TYPES OF MUNICIPAL INCINERATION PARTICULATE CONTROL SYSTEMS[a]

Type of system	Efficiency, %
Settling chamber	0 to 30
Settling chamber and water spray	30 to 60
Wetted baffles	60
Mechanical collector	30 to 80
Scrubber	80 to 95
Electrostatic precipitator	90 to 96
Fabric filter	97 to 99

[a] References 3, 5, 6, and 17 through 21.

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2.2 AUTOMOBILE BODY INCINERATION

Revised by Robert Rosensteel

2.2.1 Process Description

Auto incinerators consist of a single primary combustion chamber in which one or several partially stripped cars are burned. (Tires are removed.) Approximately 30 to 40 minutes is required to burn two bodies simultaneously.[2] As many as 50 cars per day can be burned in this batch-type operation, depending on the capacity of the incinerator. Continuous operations in which cars are placed on a conveyor belt and passed through a tunnel-type incinerator have capacities of more than 50 cars per 8-hour day.

2.2.2 Emissions and Controls[1]

Both the degree of combustion as determined by the incinerator design and the amount of combustible material left on the car greatly affect emissions. Temperatures on the order of 1200°F (650°C) are reached during auto body incineration.[2] This relatively low combustion temperature is a result of the large incinerator volume needed to contain the bodies as compared with the small quantity of combustible material. The use of overfire air jets in the primary combustion chamber increases combustion efficiency by providing air and increased turbulence.

In an attempt to reduce the various air pollutants produced by this method of burning, some auto incinerators are equipped with emission control devices. Afterburners and low-voltage electrostatic precipitators have been used to reduce particulate emissions; the former also reduces some of the gaseous emissions.[3,4] When afterburners are used to control emissions, the temperature in the secondary combustion chamber should be at least 1500°F (815°C). Lower temperatures result in higher emissions. Emission factors for auto body incinerators are presented in Table 2.2-1.

Table 2.2-1. EMISSION FACTORS FOR AUTO BODY INCINERATION[a]
EMISSION FACTOR RATING: B

Pollutants	Uncontrolled		With afterburner	
	lb/car	kg/car	lb/car	kg/car
Particulates[b]	2	0.9	1.5	0.68
Carbon monoxide[c]	2.5	1.1	Neg	Neg
Hydrocarbons (CH_4)[c]	0.5	0.23	Neg	Neg
Nitrogen oxides (NO_2)[d]	0.1	0.05	0.02	0.01
Aldehydes (HCOH)[d]	0.2	0.09	0.06	0.03
Organic acids (acetic)[d]	0.21	0.10	0.07	0.03

[a] Based on 250 lb (113 kg) of combustible material on stripped car body.
[b] References 2 and 4.
[c] Based on data for open burning and References 2 and 5.
[d] Reference 3.

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2.3 CONICAL BURNERS

2.3.1 Process Description[1]

Conical burners are generally a truncated metal cone with a screened top vent. The charge is placed on a raised grate by either conveyor or bulldozer; however, the use of a conveyor results in more efficient burning. No supplemental fuel is used, but combustion air is often supplemented by underfire air blown into the chamber below the grate and by overfire air introduced through peripheral openings in the shell.

2.3.2 Emissions and Controls

The quantities and types of pollutants released from conical burners are dependent on the composition and moisture content of the charged material, control of combustion air, type of charging system used, and the condition in which the incinerator is maintained. The most critical of these factors seems to be the level of maintenance on the incinerators. It is not uncommon for conical burners to have missing doors and numerous holes in the shell, resulting in excessive combustion air, low temperatures, and, therefore, high emission rates of combustible pollutants.[2]

Particulate control systems have been adapted to conical burners with some success. These control systems include water curtains (wet caps) and water scrubbers. Emission factors for conical burners are shown in Table 2.3-1.

Table 2.3-1. EMISSION FACTORS FOR WASTE INCINERATION IN CONICAL BURNERS WITHOUT CONTROLS[a]

EMISSION FACTOR RATING: B

Type of waste	Particulates		Sulfur oxides		Carbon monoxide		Hydrocarbons		Nitrogen oxides	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Municipal refuse[b]	20(10 to 60)[c,d]	10	2	1	60	30	20	10	5	2.5
Wood refuse[e]	1[f]	0.5	0.1	0.05	130	65	11	5.5	1	0.5
	7[g]	3.5								
	20[h]	10								

[a] Moisture content as fired is approximately 50 percent for wood waste.

[b] Except for particulates, factors are based on comparison with other waste disposal practices.

[c] Use high side of range for intermittent operations charged with a bulldozer.

[d] Based on Reference 3.

[e] References 4 through 9.

[f] Satisfactory operation: properly maintained burner with adjustable underfire air supply and adjustable, tangential overfire air inlets, approximately 500 percent excess air and 700°F (370°C) exit gas temperature.

[g] Unsatisfactory operation: properly maintained burner with radial overfire air supply near bottom of shell, approximately 1200 percent excess air and 400°F (204°C) exit gas temperature.

[h] Very unsatisfactory operation: Improperly maintained burner with radial overfire air supply near bottom of shell and many gaping holes in shell, approximately 1500 percent excess air and 400°F (204°C) exit gas temperature.

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2.4 OPEN BURNING

revised by Tom Lahre
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2.4.1 General[1]

Open burning can be done in open drums or baskets, in fields and yards, and in large open dumps or pits. Materials commonly disposed of in this manner are municipal waste, auto body components, landscape refuse, agricultural field refuse, wood refuse, bulky industrial refuse, and leaves.

2.4.2 Emissions[1-19]

Ground-level open burning is affected by many variables including wind, ambient temperature, composition and moisture content of the debris burned, and compactness of the pile. In general, the relatively low temperatures associated with open burning increase the emission of particulates, carbon monoxide, and hydrocarbons and suppress the emission of nitrogen oxides. Sulfur oxide emissions are a direct function of the sulfur content of the refuse. Emission factors are presented in Table 2.4-1 for the open burning of municipal refuse and automobile components.

Table 2.4-1. EMISSION FACTORS FOR OPEN BURNING OF NONAGRICULTURAL MATERIAL
EMISSION FACTOR RATING: B

	Particulates	Sulfur oxides	Carbon monoxide	Hydrocarbons (CH_4)	Nitrogen oxides
Municipal refuse[a]					
lb/ton	16	1	85	30	6
kg/MT	8	0.5	42	15	3
Automobile components[b,c]					
lb/ton	100	Neg.	125	30	4
kg/MT	50	Neg.	62	15	2

[a] References 2 through 6.
[b] Upholstery, belts, hoses, and tires burned in common.
[c] Reference 2.

Emissions from agricultural refuse burning are dependent mainly on the moisture content of the refuse and, in the case of the field crops, on whether the refuse is burned in a headfire or a backfire. (Headfires are started at the upwind side of a field and allowed to progress in the direction of the wind, whereas backfires are started at the downwind edge and forced to progress in a direction opposing the wind.) Other variables such as fuel loading (how much refuse material is burned per unit of land area) and how the refuse is arranged (that is, in piles, rows, or spread out) are also important in certain instances. Emission factors for open agricultural burning are presented in Table 2.4-2 as a function of refuse type and also, in certin instances, as a function of burning techniques and/or moisture content when these variables are known to significantly affect emissions. Table 2.4-2 also presents typical fuel loading values associated with each type of refuse. These values can be used, along with the corresponding emission factors, to estimate emissions from certain categories of agricultural burning when the specific fuel loadings for a given area are not known.

Emissions from leaf burning are dependent upon the moisture content, density, and ignition location of the leaf piles. Increasing the moisture content of the leaves generally increases the amount of carbon monoxide, hydrocarbon, and particulate emissions. Increasing the density of the piles increases the amount of hydrocarbon and particulate emissions, but has a variable effect on carbon

Table 2.4-2. EMISSION FACTORS AND FUEL LOADING FACTORS FOR OPEN BURNING OF AGRICULTURAL MATERIALS[a]
EMISSION FACTOR RATING: B

	Emission factors						Fuel loading factors (waste production)	
	Particulate[b]		Carbon monoxide		Hydrocarbons (as C_6H_{14})			
Refuse category	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	ton/acre	MT/hectare
Field crops[c]								
Unspecified	21	11	117	58	23	12	2.0	4.5
Burning technique not significant[d]								
Asparagus[e]	40	20	150	75	85	42	1.5	3.4
Barley	22	11	157	78	19	10	1.7	3.8
Corn	14	7	108	54	16	8	4.2	9.4
Cotton	8	4	176	88	6	3	1.7	3.8
Grasses	16	8	101	50	19	10		
Pineapple[f]	8	4	112	56	8	4		
Rice[g]	9	4	83	41	10	5	3.0	6.7
Safflower	18	9	144	72	26	13	1.3	2.9
Sorghum	18	9	77	38	9	4	2.9	6.5
Sugar cane[h]	7	4	71	35	10	5	11.0	24.0
Headfire burning[i]								
Alfalfa	45	23	106	53	36	18	0.8	1.8
Bean (red)	43	22	186	93	46	23	2.5	5.6
Hay (wild)	32	16	139	70	22	11	1.0	2.2
Oats	44	22	137	68	33	16	1.6	3.6
Pea	31	16	147	74	38	19	2.5	5.6
Wheat	22	11	128	64	17	9	1.9	4.3
Backfire burning[j]								
Alfalfa	29	14	119	60	37	18	0.8	1.8
Bean (red), pea	14	7	148	72	25	12	2.5	5.6
Hay (wild)	17	8	150	75	17	8	1.0	2.2
Oats	21	11	136	68	18	9	1.6	3.6
Wheat	13	6	108	54	11	6	1.9	4.3
Vine crops	5	3	51	26	7	4	2.5	5.6
Weeds								
Unspecified	15	8	85	42	12	6	3.2	7.2
Russian thistle (tumbleweed)	22	11	309	154	2	1	0.1	0.2
Tules (wild reeds)	5	3	34	17	27	14		
Orchard crops[c,k,l]								
Unspecified	6	3	52	26	10	5	1.6	3.6
Almond	6	3	46	23	8	4	1.6	3.6
Apple	4	2	4[illegible]	21	4	2	2.3	5.2
Apricot	6	3	49	24	8	4	1.8	4.0
Avocado	21	10	116	58	32	16	1.5	3.4
Cherry	8	4	44	22	10	5	1.0	2.2
Citrus (orange, lemon)	6	3	81	40	12	6	1.0	2.2
Date palm	10	5	56	28	7	4	1.0	2.2
Fig	7	4	57	28	10	5	2.2	4.9

Table 2.4-2 (continued). EMISSION FACTORS AND FUEL LOADING FACTORS FOR OPEN BURNING OF AGRICULTURAL MATERIALS[a]
EMISSION FACTOR RATING: B

Refuse category	Emission factors						Fuel loading factors (waste production)	
	Particulate[b]		Carbon monoxide		Hydrocarbons (as C_6H_{14})			
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	ton/acre	MT/hectare
Orchard crops[c,k,l] (continued)								
Nectarine	4	2	33	16	4	2	2.0	4.5
Olive	12	6	114	57	18	9	1.2	2.7
Peach	6	3	42	21	5	2	2.5	5.6
Pear	9	4	57	28	9	4	2.6	5.8
Prune	3	2	42	21	3	2	1.2	2.7
Walnut	6	3	47	24	8	4	1.2	2.7
Forest residues								
Unspecified[m]	17	8	140	70	24	12	70	157
Hemlock, Douglas fir, cedar[n]	4	2	90	45	5	2		
Ponderosa pine[o]	12	6	195	98	14	7		

[a] Factors expressed as weight of pollutant emitted per weight of refuse material burned.

[b] Particulate matter from most agricultural refuse burning has been found to be in the submicrometer size range.[12]

[c] References 12 and 13 for emission factors; Reference 14 for fuel loading factors.

[d] For these refuse materials, no significant difference exists between emissions resulting from headfiring or backfiring.

[e] These factors represent emissions under typical high moisture conditions. If ferns are dried to less than 15 percent moisture, particulate emissions will be reduced by 30 percent, CO emission by 23 percent, and HC by 74 percent.

[f] When pineapple is allowed to dry to less than 20 percent moisture, as it usually is, the firing technique is not important. When headfired above 20 percent moisture, particulate emission will increase to 23 lb/ton (11.5 kg/MT) and HC will increase to 12 lb/ton (6 kg/MT). See Reference 11.

[g] This factor is for dry (<15 percent moisture) rice straw. If rice straw is burned at higher moisture levels, particulate emission will increase to 29 lb/ton (14.5 kg/MT), CO emission to 161 lb/ton (80.5 kg/MT), and HC emission to 21 lb/ton (10.5 kg/MT).

[h] See Section 6.12 for discussion of sugar cane burning.

[i] See accompanying text for definition of headfiring.

[j] See accompanying text for definition of backfiring. This category, for emission estimation purposes, includes another technique used occasionally for limiting emissions, called into-the-wind striplighting, which involves lighting fields in strips into the wind at 100-200 m (300-600 ft) intervals.

[k] Orchard prunings are usually burned in piles. No significant difference in emission results from burning a "cold pile" as opposed to using a roll-on technique, where prunings are bulldozed onto a bed of embers from a preceding fire.

[l] If orchard removal is the purpose of a burn, 30 ton/acre (66 MT/hectare) of waste will be produced.

[m] Reference 10. Nitrogen oxide emissions estimated at 4 lb/ton (2 kg/MT).

[n] Reference 15.

[o] Reference 16.

monoxide emissions. Arranging the leaves in conical piles and igniting around the periphery of the bottom proves to be the least desirable method of burning. Igniting a single spot on the top of the pile decreases the hydrocarbon and particulate emissions. Carbon monoxide emissions with top ignition decrease if moisture content is high but increase if moisture content is low. Particulate, hydrocarbon, and carbon monoxide emissions from windrow ignition (piling the leaves into a long row and igniting one end, allowing it to burn toward the other end) are intermediate between top and bottom ignition. Emission factors for leaf burning are presented in Table 2.4-3.

For more detailed information on this subject, the reader should consult the references cited at the end of this section.

Table 2.4-3. EMISSION FACTORS FOR LEAF BURNING[18,19]
EMISSION FACTOR RATING: B

Leaf species	Particulate[a,b]		Carbon monoxide[a]		Hydrocarbons[a,c]	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Black Ash	36	18	127	63.5	41	20.5
Modesto Ash	32	16	163	81.5	25	12.5
White Ash	43	21.5	113	57	21	10.5
Catalpa	17	8.5	89	44.5	15	7.5
Horse Chestnut	54	27	147	73.5	39	19.5
Cottonwood	38	19	90	45	32	16
American Elm	26	13	119	59.5	29	14.5
Eucalyptus	36	18	90	45	26	13
Sweet Gum	33	16.5	140	70	27	13.5
Black Locust	70	35	130	65	62	31
Magnolia	13	6.5	55	27.5	10	5
Silver Maple	66	33	102	51	25	12.5
American Sycamore	15	7.5	115	57.5	8	4
California Sycamore	10	5	104	52	5	2.5
Tulip	20	10	77	38.5	16	8
Red Oak	92	46	137	68.5	34	17
Sugar Maple	53	26.5	108	54	27	13.5
Unspecified	38	19	112	56	26	13

[a] These factors are an arithmetic average of the results obtained by burning high- and low-moisture content conical piles ignited either at the top or around the periphery of the bottom. The windrow-arrangement was only tested on Modesto Ash, Catalpa, American Elm, Sweet Gum, Silver Maple, and Tulip, and the results are included in the averages for these species.

[b] The majority of particulates are submicron in size.

[c] Tests indicate hydrocarbons consist, on the average, of 42% olefins, 32% methane, 8% acetylene, and 13% other saturates.

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2.5 SEWAGE SLUDGE INCINERATION

By Thomas Lahre

2.5.1 Process Description [1-3]

Incineration is becoming an important means of disposal for the increasing amounts of sludge being produced in sewage treatment plants. Incineration has the advantages of both destroying the organic matter present in sludge, leaving only an odorless, sterile ash, as well as reducing the solid mass by about 90 percent. Disadvantages include the remaining, but reduced, waste disposal problem and the potential for air pollution. Sludge incineration systems usually include a sludge pretreatment stage to thicken and dewater the incoming sludge, an incinerator, and some type of air pollution control equipment (commonly wet scrubbers).

The most prevalent types of incinerators are multiple hearth and fluidized bed units. In multiple hearth units the sludge enters the top of the furnace where it is first dried by contact with the hot, rising, combustion gases, and then burned as it moves slowly down through the lower hearths. At the bottom hearth any residual ash is then removed. In fluidized bed reactors, the combustion takes place in a hot, suspended bed of sand with much of the ash residue being swept out with the flue gas. Temperatures in a multiple hearth furnace are 600°F (320°C) in the lower, ash cooling hearth; 1400 to 2000°F (760 to 1100°C) in the central combustion hearths, and 1000 to 1200°F (540 to 650°C) in the upper, drying hearths. Temperatures in a fluidized bed reactor are fairly uniform, from 1250 to 1500°F (680 to 820°C). In both types of furnace an auxiliary fuel may be required either during startup or when the moisture content of the sludge is too high to support combustion.

2.5.2 Emissions and Controls [1,2,4-7]

Because of the violent upwards movement of combustion gases with respect to the burning sludge, particulates are the major emissions problem in both multiple hearth and fluidized bed incinerators. Wet scrubbers are commonly employed for particulate control and can achieve efficiencies ranging from 95 to 99+ percent.

Although dry sludge may contain from 1 to 2 percent sulfur by weight, sulfur oxides are not emitted in significant amounts when sludge burning is compared with many other combustion processes. Similarly, nitrogen oxides, because temperatures during incineration do not exceed 1500°F (820°C) in fluidized bed reactors or 1600 to 2000°F (870 to 1100°C) in multiple hearth units, are not formed in great amounts.

Odors can be a problem in multiple hearth systems as unburned volatiles are given off in the upper, drying hearths, but are readily removed when afterburners are employed. Odors are not generally a problem in fluidized bed units as temperatures are uniformly high enough to provide complete oxidation of the volatile compounds. Odors can also emanate from the pretreatment stages unless the operations are properly enclosed.

Emission factors for sludge incinerators are shown in Table 2.5-1. It should be noted that most sludge incinerators operating today employ some type of scrubber.

Table 2.5-1. EMISSION FACTORS FOR SEWAGE SLUDGE INCINERATORS
EMISSION FACTOR RATING: B

Pollutant	Emissions[a]			
	Uncontrolled[b]		After scrubber	
	lb/ton	kg/MT	lb/ton	kg/MT
Particulate[c]	100	50	3	1.5
Sulfur dioxide[d]	1	0.5	0.8	0.4
Carbon monoxide[e]	Neg	Neg	Neg	Neg
Nitrogen oxides[d] (as NO_2)	6	3	5	2.5
Hydrocarbons[d]	1.5	0.75	1	0.5
Hydrogen chloride gas[d]	1.5	0.75	0.3	0.15

[a] Unit weights in terms of dried sludge.

[b] Estimated from emission factors after scrubbers.

[c] References 6-9.

[d] Reference 8.

[e] References 6, 8.

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Chapter 6

Combustion Control and Instrumentation

A portion of the material presented in this chapter was adapted and edited from Chapter 35, *Steam, Its Generation and Use*, Babcock & Wilcox Company, 39th Edition, 1978.

INTRODUCTION

This chapter presents a brief overview of the logic that governs combustion controls. Emphasis is placed on the overall purpose of control, and several examples of logic-sequencing are presented. Instrumentation is discussed, both in terms of requirements for good operation and in terms of long-term recordkeeping.

Combustion processes are normally designed to provide thermal energy for a particular end use. The most common application is to generate steam for electric power production or for a multitude of other manufacturing or heating processes. Systems which do not produce steam usually produce hot gases, either directly as combustion products or indirectly using heat exchangers. Gas turbine-drive electric generation is an example of the direct application of hot gases; a gas-fired space heater is an example of indirect application.

All applications of combustion usually provide for a variable energy demand because the end use is seldom constant with time. Variable energy demand introduces varying fuel and air requirements, since energy output rates can only be altered through corresponding changes of input energy. Control of the thermal energy source requires realization of two major objectives:

1. Maintain high combustion efficiency at all energy input rates and do so while maintaining emissions which are within acceptable standards, and
2. Maintain appropriate thermal energy states in the equipment for which energy is supplied (steam pressure, temperature).

The thermal energy states cited are the common variables which are used to key the combustion control system. Steam pressure as well as temperature are both important to the proper operation of a steam turbine-driven alternator. Steam pressure, however, is the more important of the two, since steam turbine speed control is pressure sensitive. A power demand change requires either an increase or decrease of steam flow. This change in turn requires combustion control which increases or decreases the energy release rate and the steam generation. Increased steam flow which is not accompanied by corresponding increased steam generation will cause a drop in steam pressure. The allowable pressure fluctuation is usually less than ±2% of the design value, which serves to illustrate the precision a system can be expected to have.

Process applications may require control of both rate of energy supply and temperature. Where heat exchange is employed, temperature control may be possible at the exchanger, within limits; however, the energy rate control would influence the combustion process. Various drying processes, such as lumber-drying kilns, veneer dryers, crop dryers, etc., are examples of this kind of system.

Combustion Control

The general requirements outlined above can be translated into more specific requirements for combustion control systems. All combustion systems must meet a variable load demand through an adjustment of the fuel input rate proportional to the load, with a simultaneous adjustment to air flow, to assure maintenance of the most efficient air-fuel ratio.

This seemingly straightforward concept suggests a relatively simple solution is probably available. Such a conclusion would be wrong, because the interactions which occur are not simple. Furnace air is generally supplied through a forced-draft fan assembly that involves one or more fans. Where one fan is utilized, distribution may be through several alternate paths, such as primary and secondary air for burners. Air pressure and quantity must be controlled by altered fan speed and damper settings. A change in the forced draft (to follow a change in fuel flow) requires a change in the induced draft if the desired furnace pressure (draft) is to be maintained. Small systems, which utilize chimney draft to produce the required induced draft, must have adequate dampers.

The above sequence of control is made more difficult by the variability of fuel properties. The basic chemistry of combustion, shown in Equations 2-1 and 2-3 in Chapter 2 of this manual, clearly sets the air requirement per unit of fuel and thereby the energy production which can be expected. Any change in composition is immediately reflected by an increase or decrease in the energy output and air requirements. A combustion control system designed to operate with fuel flow keyed to steam flow would require simultaneous sampling of flue gas composition to insure property variation would be accommodated.

This aspect of the combustion control problem can be pinpointed by considering a system which suddenly receives fuel having a higher moisture content than normal. This situation occurs in mass-burning incinerators, when especially wet municipal waste comes into the flow, or in a coal-burning plant, where very wet coal suddenly enters the feeders. Increased moisture reduces the input-energy rate and lowers the furnace temperature making an increase in fuel flow necessary. If the unit involved is a radiant steam generator, high-moisture fuel would cause reduced load capability. An example is a coal-fired unit designed to operate on eastern coal that has been switched to high-moisture western coal. The flame temperature would be reduced, which would cause a reduction of the radiant energy transfer. This reduction would be accompanied by increased energy input in the convective superheater. This change could very well exceed the capability of the "attemperator control" (superheater steam temperature controller). The superheater-steam temperature would become excessive, requiring that the unit load be reduced to bring the situation back under control.

Combustion controls must be designed to deal with the particular fuels to be fired and the fuel rates inherent to the fuel-feeding mechanism. A great variety of combustion control systems have been developed over the years to fit the needs of particular applications. Loan demands, operating philosophy, plant layout, and types of firing must be considered before the selection of a system is made. Attachments 6-2 through 6-5 illustrate several of the systems that have been developed for various types of fuel firing. The control symbols shown in these illustrations have been tabulated in Attachment 6-1.

Stoker-Fired Boilers

Stoker-fired boilers are regulated by positioning fuel and combustion air from changes in steam pressure. A change in steam demand initiates a signal from the steam-pressure controller – through the boiler master controller – to increase or decrease both fuel and air simultaneously and in parallel to satisfy the demand. As long as the pressure differs from the set-point value, the steam-pressure controller will continue to integrate the fuel and air until the pressure has returned to its set-point (see Attachment 6-2).

A second part of the control system senses the steam-flow and air-flow and makes a comparison with calibrated values for the unit. Any differences sensed will create an error signal which is used to fine-tune the forced-draft damper, thereby assuring the desired fuel-air ratio

Furnace draft is regulated separately through the use of a furnace-draft controller and a power operator that positions the uptake damper.

Gas and Oil-Fired Boilers

Attachment 6-3 illustrates a system applicable to the burning of gas and oil, separately or together. The fuel and air flows are controlled by steam pressure through the boiler master, with the fuel readjusted by the fuel-flow air-flow controller. The oil- or gas-header pressure may be used as an index of fuel flow and the windbox-to-furnace differential as an index of air flow on a per-burner basis. Such indices are often used for single-burner boilers.

Pulverized Coal-Fired Boilers

Attachment 6-4 illustrates a sophisticated combustion control system used on larger boilers having several pulverizers, each supplying a group of burners. Both primary and secondary air are admitted and controlled on a pulverizer-unit basis.

The boiler firing-rate demand is compared to the total measured fuel flow (summation of all feeders delivering coal) to develop the demand to the pulverizer master controller. The pulverizer master demand signal is then applied in parallel to all operating pulverizers. All pulverizers have duplicate controls.

The individually biased pulverizer demand signal is applied in a parallel mode, as demands vary for coal-feeder speed, primary-air flow, and total air flow for the pulverizer group. When an error develops between demanded and measured primary-air flow or total-air flow, proportional and integral action will be instituted through the controllers to adjust the primary or secondary air dampers to reduce the error to zero. A low primary-air flow or total-air flow cutback is applied in the individual pulverizer control. If either measured primary-air flow or total-air flow is low, relative to coal rate (feeder speed) demand, this condition is sensed in the coal-feeder control, which reduces the demand to that equivalent to the measured primary-air flow. A minimum pulverizer-load limit, a minimum primary-air-flow limit, and a minimum total-air-flow limit are applied to the respective demands to keep the pulverizers above their minimum safe operating load. This maintains sufficient burner nozzle velocities at all times and assures the primary and total air-fuel ratios are continuously controlled at prescribed levels.

Cyclone-Fired Furnaces

Cyclone-furnace controls shown in Attachment 6-5 are similar to those for pulverized-fired units, although the cyclone functions as an individual furnace.

Where a unit employs multi-cyclones, feeder drives are calibrated so that all feeders operate at the same speed for a given master signal. The total-air flow is controlled by the velocity damper in each cyclone to maintain the proper fuel-air relationship. This air flow is automatically compensated for temperature in order to provide the correct amount of air under all boiler loads. The total-air flow to the cyclone is controlled by the windbox-to-furnace differential pressure, which is varied as a function of load, to increase or decrease the forced-draft-fan output.

Automatic compensation for the number of cyclones in service has been incorporated, along with the added feature of an oxygen analyzer. This gas analyzer is a component for most control systems and serves as an important aid to the operator in monitoring excess air for optimum firing condition.

Instrumentation

Instruments are installed in combustion systems for a number of reasons. Codes, both national and local, may prescribe minimum requirements necessary for the protection of the public safety, health, and welfare. Aside from these obvious public requirements, however, proper plant operation requires the operating personnel to have a working knowledge of pressures, temperatures, and flows throughout the system. Accurate records of fuel flows, steam or gas flows, power, etc., are required in order to calculate and control operating costs. For a given plant burning selected fuels, predetermined instrument values can assist crews in maintaining proper combustion. Instruments can be categorized as serving the following functions:

1. Operating guidance
2. Performance computation and analysis
3. Costs and cost allocation
4. Maintenance guidance (particularly preventive maintenance).

Instruments employed to provide useful information for operating guidance can also provide information for other functions listed. Steam-flow, air-flow, and fuel-flow measurements aid operators to assure good combustion. Readout from these devices can be recorded, processed by computer, and rendered into cost analyses, efficiency studies, or other management functions. Measurements in a combustion system can be broken down into a variety of general categories. A brief outline of the types of information or their applications is included within these general categories:

1. Flow measurements—normally accomplished by differential-head meters:
   a. Steam-flow meters—usually provided for each individual boiler, as well as for the collective output from a group of boilers, turbine or pump supply, industrial processes, and auxiliary uses
   b. Air-flow meters—main combustion air, secondary air flows
   c. Water-flow meters—boiler feed water flow, condensing water flow, process water flow, auxiliary uses.
2. Fuel flow:
   a. Coal—weighed in batches, or by devices capable of continuous-steam weighing
   b. Gas—usually metered by differential head devices—also measured by positive displacement meters
   c. Liquid fuels—metered by positive displacement meters
   d. Solids other than coal—usually measured by weighing devices similar to those employed for coal.
3. Pressure measurements:
   a. Steam pressure—steam generator outlet; turbines or pumps; inlet-to-feed water heaters, steam condensers, industrial processes
   b. Furnace draft
   c. Forced-air supply—primary air; secondary air; overfire air jet supply air
   d. Induced-draft fan outlet
   e. Emission-control device, inlet and outlet.
4. Temperature:
   a. Steam temperature at various points in a system where steam is expected to be superheated
   b. Air temperatures:
      (1) Into and out of preheaters
      (2) At appropriate places in primary- or secondary-air supply for various fuel burners.
   c. Flue gas:
      (1) At furnace outlet
      (2) Superheater inlet and outlet
      (3) Inlet and outlet of air preheater
      (4) Into and out of emission-control devices
   d. Miscellaneous equipment where temperature measurement is important, such as direct flame afterburner combustion chambers, veneer dryers, etc.
5. Flue gas analysis
   a. CO_2 and O_2 meters aid combustion control
   b. SO_2 and NO_x meters aid in proper emissions evaluation and control.

The degree of control sophistication is a plant-size function, which is another way of saying an economic one. Combustion systems which consume very large quantities of fuel will usually be well instrumented and will provide highly automatic control and data processing. Microprocessors are used to ensure closed loop control of excess air to ensure high combustion efficiency. Small plants normally have less sophisticated controls and may not employ computers for data processing.

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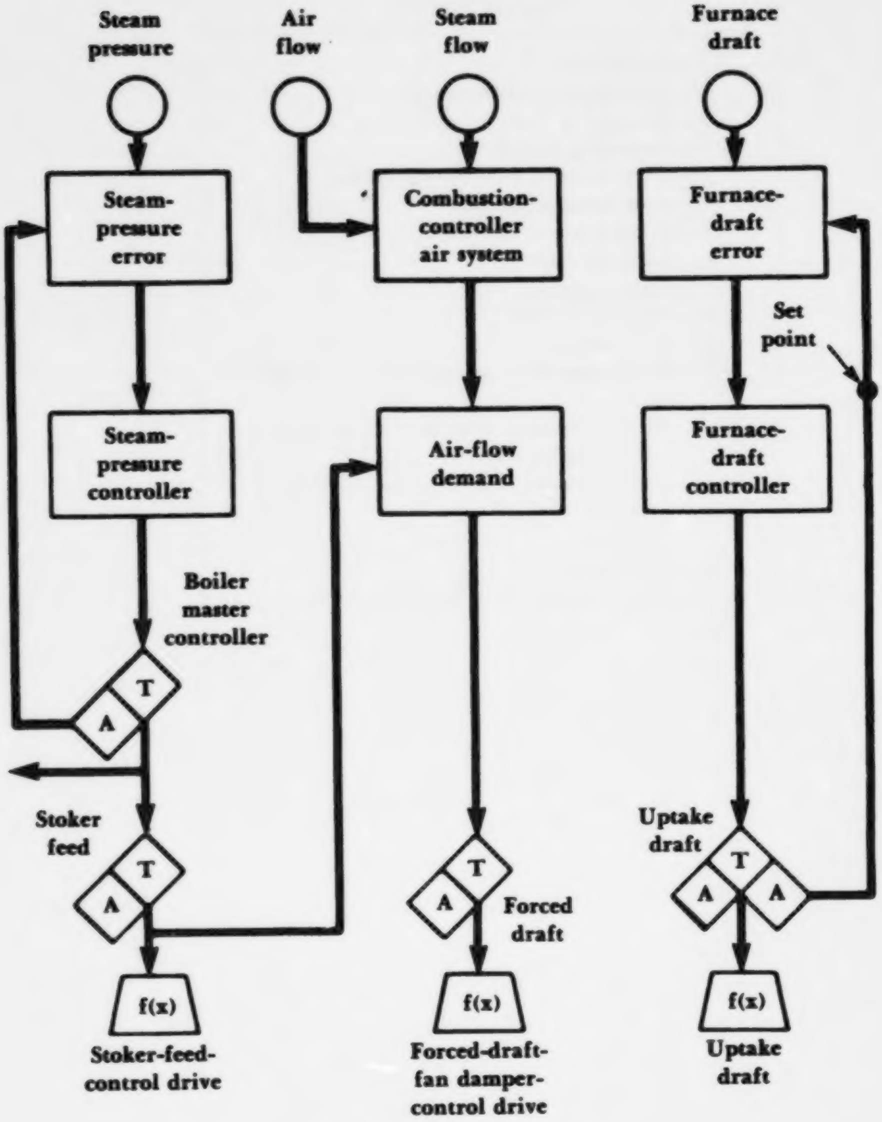
Attachment 6-1. Control symbols[1]

Table 1
Control Symbols

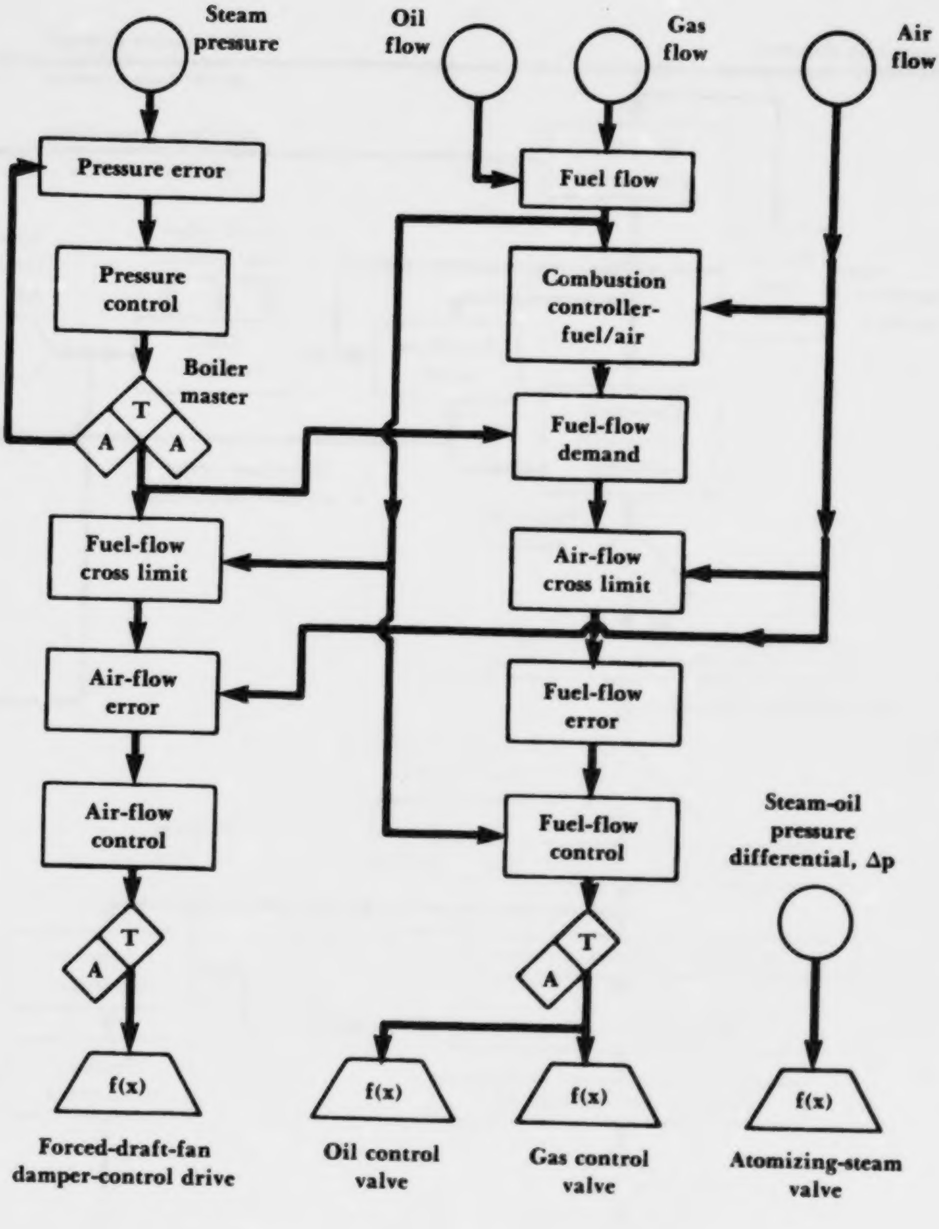
O—Transmitter
K—Propotional action (gain)
∫—Integral action
Σ—Summing action
Δ—Difference or subtracting action
<—Low select auctioneer
>—High select auctioneer
≯—Low limiting
≮—High limiting
d/dt—Derivative (rate)
Σ/n—Averaging
◇A◇T—Hand-automatic selector station (analog control)
◇A◇T◇A—Hand-automatic selector station (analog control) with bias
H/A—Hand-automatic selector station (digital control)
T—Transfer
±—Bias action
f(x)—Power device, (valves, drives, etc.)

Attachment 6-2. Diagram of a combustion control for a spread stoker, fired boiler[1]



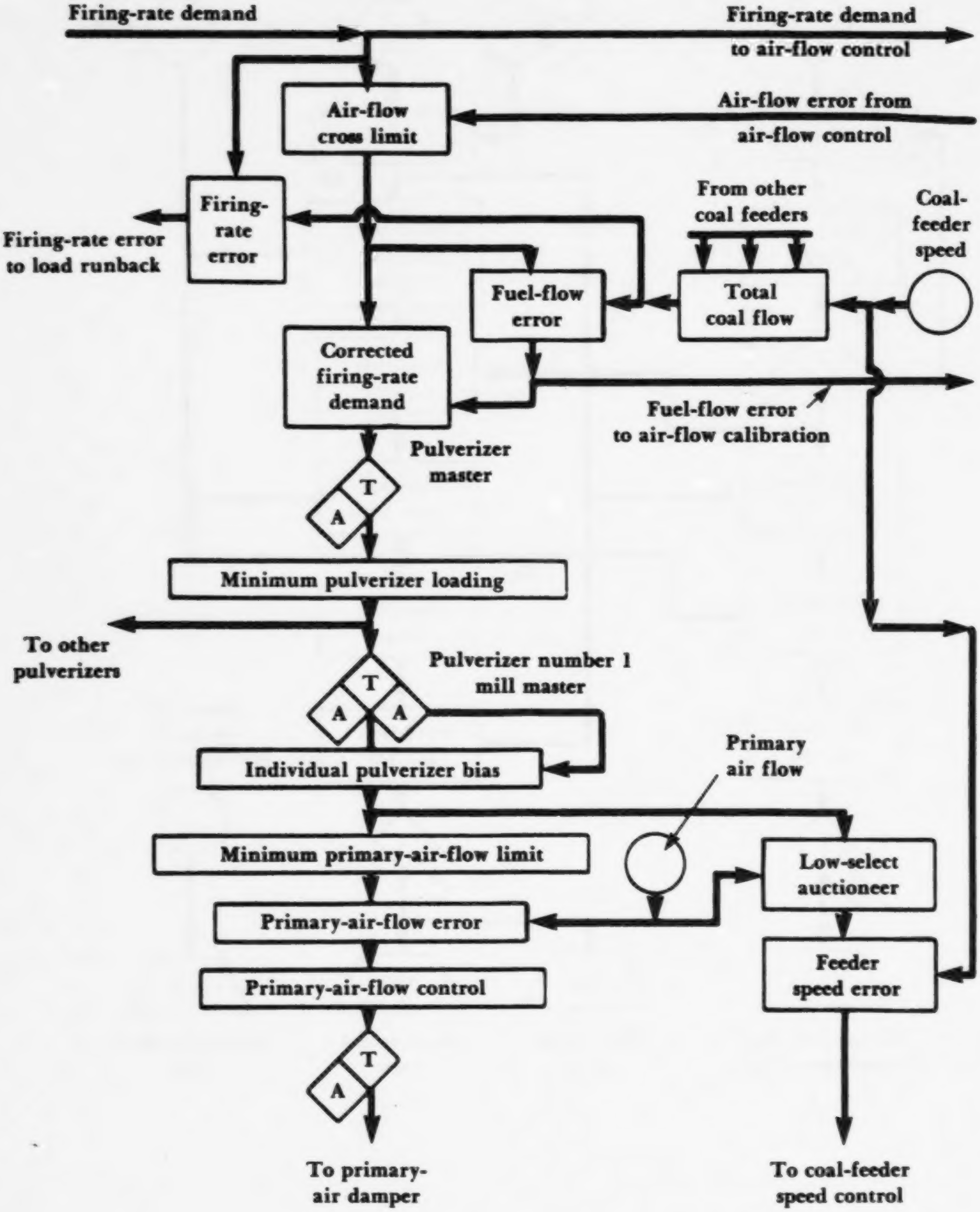
Steam pressure
Air flow
Steam flow
Furnace draft
Steam-pressure error
Combustion-controller air system
Furnace-draft error
Set point
Steam-pressure controller
Air-flow demand
Furnace-draft controller
Boiler master controller
T
A
Stoker feed
T
A
T
A
Forced draft
Uptake draft
T
A
A
f(x)
f(x)
f(x)
Stoker-feed-control drive
Forced-draft-fan damper-control drive
Uptake draft

Attachment 6-3. Diagram of combustion control for a gas- and oil-fired boiler[1]

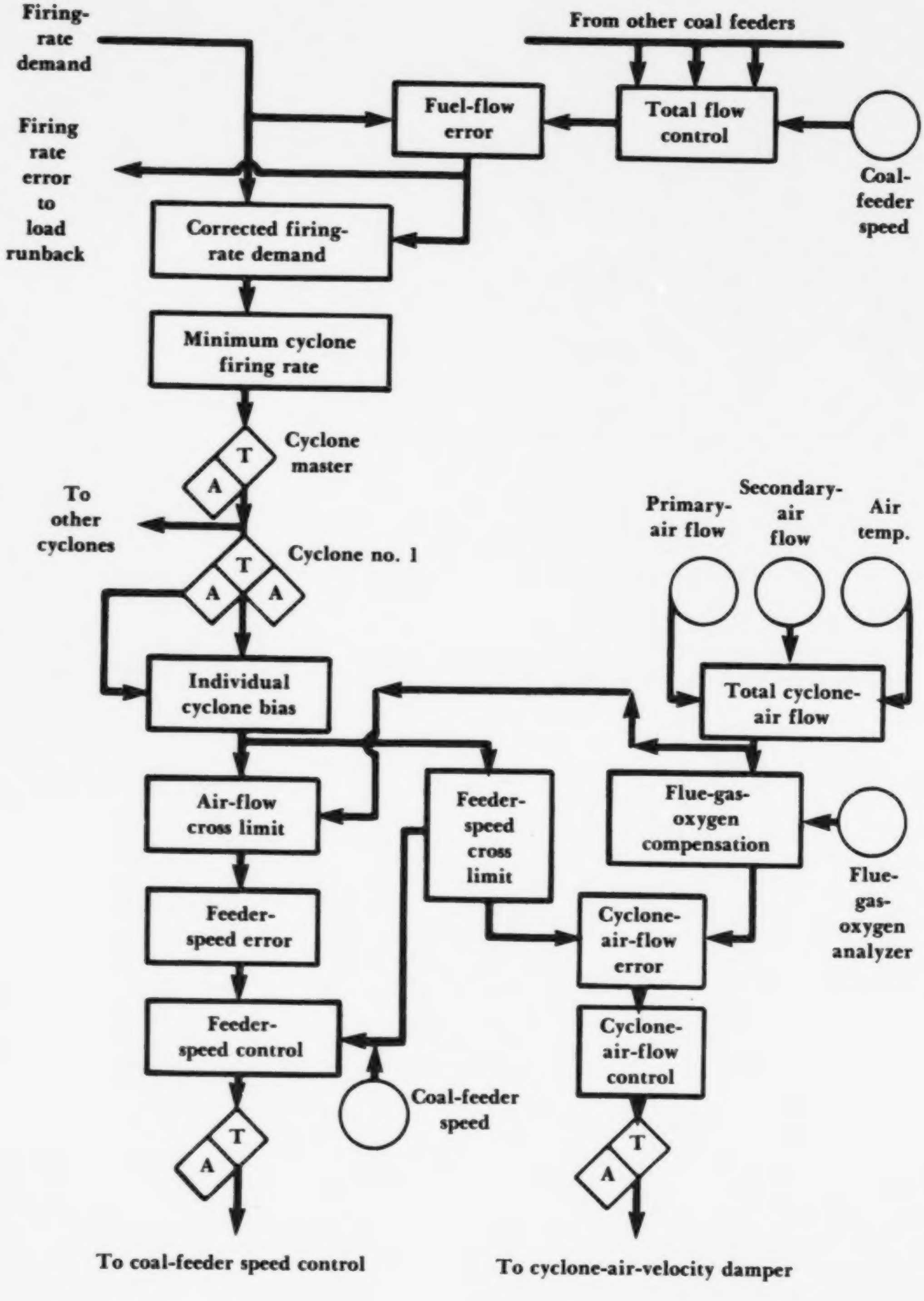


Steam pressure
Oil flow
Gas flow
Air flow
Pressure error
Fuel flow
Pressure control
Combustion controller-fuel/air
Boiler master
T
A
A
Fuel-flow demand
Fuel-flow cross limit
Air-flow cross limit
Air-flow error
Fuel-flow error
Air-flow control
Fuel-flow control
Steam-oil pressure differential, Δp
T
A
T
A
f(x)
f(x)
f(x)
f(x)
Forced-draft-fan damper-control drive
Oil control valve
Gas control valve
Atomizing-steam valve

Attachment 6-4. Diagram of combustion control for a pulverized-coal boiler[1]


Firing-rate demand
Firing-rate demand to air-flow control
Air-flow cross limit
Air-flow error from air-flow control
Firing-rate error
Firing-rate error to load runback
From other coal feeders
Coal-feeder speed
Fuel-flow error
Total coal flow
Corrected firing-rate demand
Fuel-flow error to air-flow calibration
Pulverizer master
T
A
Minimum pulverizer loading
To other pulverizers
Pulverizer number 1 mill master
T
A
A
Individual pulverizer bias
Primary air flow
Minimum primary-air-flow limit
Low-select auctioneer
Primary-air-flow error
Feeder speed error
Primary-air-flow control
T
A
To primary-air damper
To coal-feeder speed control

Attachment 6-5. Diagram of combustion control for a cyclone-fired boiler[1]


Firing-rate demand
From other coal feeders
Fuel-flow error
Total flow control
Coal-feeder speed
Firing rate error to load runback
Corrected firing-rate demand
Minimum cyclone firing rate
T
A
Cyclone master
To other cyclones
T
A
A
Cyclone no. 1
Primary-air flow
Secondary-air flow
Air temp.
Individual cyclone bias
Total cyclone-air flow
Air-flow cross limit
Feeder-speed cross limit
Flue-gas-oxygen compensation
Flue-gas-oxygen analyzer
Feeder-speed error
Cyclone-air-flow error
Feeder-speed control
Cyclone-air-flow control
Coal-feeder speed
T
A
T
A
To coal-feeder speed control
To cyclone-air-velocity damper

Chapter 7

Gaseous Fuel Burning

INTRODUCTION

Burning gaseous fuels is perhaps the most straightforward of all combustion processes. No fuel preparation is necessary because gases are easily mixed with air, and the combustion reaction proceeds rapidly, once the ignition temperature is reached.

The amount of air required for complete combustion of gaseous fuels has already been discussed in Chapter 2. This chapter will present some special characteristics of gas flames, as well as the characteristic of various burners in proportioning, mixing, and burning the fuel-air mixtures in an environmentally acceptable manner.

Of the many gaseous fuels, natural gas is the most important one for large-scale stationary combustion installations. Pipeline natural gas is perhaps the closest approach to an ideal fuel. It is virtually free of sulfur and solid residues, and it is the cleanest burning of all fossil fuels. The relative ease of burning gaseous fuels, particularly natural gas, has on occasion led to reduced surveillance by the operator and resulted in surprisingly high levels of carbon monoxide in the exhaust gases (1, p. 552). This, and other air pollution concerns associated with burning gaseous fuels, will be discussed in the last section of this chapter.

Flame Combustion

There are two principal mechanisms of flame combustion producing flames of quite different appearance: blue flame and yellow flame. Blue flame results when gaseous fuel is mixed with air prior to ignition. In this instance the combustion mechanism is represented by the hydroxylation theory: hydrocarbon molecules are oxidized gradually in stages passing through hydroxylated compounds (alcohols), to aldehydes and ketones, to carbon monoxide, and eventually to CO_2 and H_2O. Incomplete combustion results in the emission of the intermediate partially oxidized compounds. However, no soot can be developed, even if the flame is quenched, since the carbon is converted to alcohols and aldehydes during the early stages of the combustion.

Yellow flame results when the fuel and air enter the combustion zone separately—without having been intimately mixed prior to ignition. The carbonic theory explains the mechanism of combustion in this instance. Hydrocarbon molecules decompose to form solid carbon particles and hydrogen when exposed to high furnace temperatures before they have had an opportunity to combine with oxygen. This process is called thermal cracking. The carbon particles are incandescent at the elevated temperatures and give the flame a yellowish appearance. Eventually sufficient oxygen, if available, will diffuse into the flame to form CO_2 and H_2O as the ultimate combustion products. Insufficient oxygen or incomplete combustion due to flame quenching will result in soot and black smoke.

Which of these two combustion mechanisms is preferable, depends on the particular application, as will be discussed later in this chapter. These theories apply also to the combustion of fuels other than gas and again point out the importance of understanding the effects of temperature, turbulence (mixing), and time on achieving complete combustion.

Gas Burning Characteristics

The function of a gas burner is to deliver fuel and air in a desired ratio to the combustion chamber, and to provide mixing and ignition of the combustible mixture.

Most gas burners employ the Bunsen principle, where at least a part of the combustion air is mixed with the gas prior to ignition (see Attachment 7-1). Under normal operation the flame consists of a bright blue inner cone at the end of the burner tube, surrounded by an envelope of lower luminosity (Attachment 7-2). The outer envelope or mantle is less sharply defined. It is blue at the base and may terminate in a yellow tip. Flame luminosity increases at low primary air rates with the inner blue cone almost disappearing into the now luminous outer cone at the lowest premix level.

The shape of the flame will depend on the mixture pressure and the amount of primary air. The latter is the percentage of the combustion air which has been premixed with the gas before combustion and is also referred to as percent premix. The remainder of the combustion air is known as the secondary air and enters the furnace directly, without having passed through the burner first. For a given burner, increasing mixture pressure will broaden the flame. Increased primary air will shorten it, as shown in Attachment 7-2 (1). Burner design, however, will have much more effect on the size and shape of the flame. Rapid mixing is likely to produce a short "bushy" flame, while delayed mixing and low velocities result in long and more slender flames.

Burning characteristics of different fuel gases are of primary importance in the burner design, and they will also determine the stable operating range for a given burner. Among these characteristics are the flame propagation velocities, some of which are listed in Attachment 7-3. Note that the maximum velocity does not occur at the stiochiometric composition. Gases with high flame propagation velocities, such as hydrogen, acetylene, ethylene, etc., are more prone to flash-back through the burner at low firing rates. On the other hand, these fast-burning gases are less likely to blow off or lift from the burner tip than flames of natural gas (mostly methane) or liquefied petroleum gases. Burners for gases with high flame velocities are, therefore, normally operated at somewhat higher primary air rates than natural gas or LPG burners.

The locations of stable flame boundaries are illustrated qualitatively in Attachment 7-4 as a function of the gas input rate. Very low amounts of primary air will lead to the yellow flame (carbonic theory) combustion mechanism with the possibility of smoke and soot formation with incomplete combustion.

Turndown is the range of maximum to minimum fuel gas input rates over which a burner will operate satisfactorily. The maximum input rate is limited by the lifting, and the eventual blow-off, of the flame when the mixture velocity exceeds the flame propagation velocity. The minimum gas rate is set by flash-back, where mixture velocity is less than flame velocity. The tapered venturi section of atmospheric burners (Attachment 7-1) is designed not only to provide mixing of the fuel gas and air, but also an increased velocity near the throat to help prevent flashback. Theoretically the flame will be stationary at a point where the flame velocity equals the mixture velocity in or out of the mixing tube. Actually, however, a relatively cool burner port will also serve to stabilize the flame. Operation of the atmospheric type burner (with natural gas) is generally satisfactory with 30—70% premix which permits about 4 to 1 turndown ratio. A high turndown ratio is desirable for cyclic loads and for applications where high heat input rates are needed during initial heat-up, but cannot be tolerated during steady operation. Considerably lower turndown ratios are adequate for continuous furnaces which are seldom started cold. Occasional longer start-up periods may be less costly than the larger, more sophisticated equipment required by a high turndown capability. If temperature distribution is not too critical, higher modulation of heat input may be achieved by either lighting or shutting off burners.

Gas Burners

There are many ways to categorize gas burners. One classification depends on how the gaseous fuel and air are brought together and mixed; such as by (a) premixing, (b) nozzle mixing, or (c) long-flame burners (2).

In gas burners of the premixing type the primary air and gas are mixed upstream from the burner ports. Most domestic gas burners are of this type, and consist of a manifold with a number of small ports. This type of burner is not capable of high heat release rates within confined volumes, thereby seriously limiting the temperatures to which objects can be heated. Multiple port gas burners are widely used for heaters, boilers, and vapor incinerators. Over a given cross-section, a multiple-port burner provides better distribution of flame and heat than a single-port unit.

Attachment 7-5 illustrates a few of the multitude of designs and techniques which have been used to deliver the fuel-air mixture to a combustion chamber. The atmospheric burner (Attachments 7-1 and 7-5.1) has already been discussed. Multiple gas jets with natural or fan draft air supply are widely used for boiler firing (Attachment 7-5.2, 7-5.3, 7-5.4, and 7-5.7). Refractory tunnels assist in heating the mixture for ignition and help protect the metal parts from high temperatures. Improved mixing can be obtained by the orientation of gas jets (7-5.2), vanes (7-5.3), or by a rotating spider (7-5.7). In the case of very low gas pressures, compressed air can be injected, as with the inspirator governor (7-5.5), which supplies complete fuel-air mixture to a number of individual burners, usually of a tunnel type. Similar burners can also be used with high pressure gas and atmospheric air. Good practice dictates that manufactured gas be available at 5 psig or higher and natural gas at 10 psig or even higher for inspirator-type burners. Inspirators cannot be used with propane or butane at any normally available gas pressures since these gases require 24 to 31 volumes of air per volume of gas. A combustion air blower will greatly increase the flexibility of a burner compared to an atmospheric unit, as well as make it capable of providing better combustion through improved control.

Nozzle-mixing gas burners do not mix the gas and air until they leave the burner port. Nozzle orifices are designed for rapid mixing of fluids as they leave. The main advantage of these burners is a greater turndown ratio. External regulators or proportioning valves are their major disadvantage.

Long (luminous) flame gas burners are used in larger furnaces where a good portion of the heat is to be transformed by radiation. Long flames are produced by injecting a low-velocity central core of gas completely surrounded by an annular air stream. With a low mixing rate, combustion will take place at the air-gas interface; radiant energy causes the gas to crack and produce luminous carbon particles in the central core. Burners based on a similar principle are also used for firing radiant tubes where delayed mixing is necessary to prevent hot spots on the tubes.

Specialized Gas Burners

There are many gas burners designed specifically for a particular application. The following is a brief presentation of typical burners to illustrate the wide range of burners available.

Excess-air gas burners are used for metallurgical heat treating furnaces, kilns, air heaters, dryers, and similar applications where superior temperature uniformity is required. These are sealed-in, nozzle-mix burners capable of producing a stable flame with several thousand percent excess air.

A mixing-plate-type burner (1, p. 181) is shown in Attachment 7-6. It operates over a very wide range of air-gas mixtures and its stability is not affected by fluctuating fuel supply. A mixing-plate burner can be used to burn waste gases with heat content as low as 55 Btu/ft^3 (4).

A lean-fuel burner has recently been patented by British Petroleum, London. This burner consists of a double, flat tubular spiral with the gas-air mixture entering from the outer edge and being preheated as it flows toward the center where the combustion takes place. Combustion products spiral outward through the adjacent tube, and transfer heat across the wall to the incoming mixture. By varying the number of turns in the spiral, sustained stable burning can be obtained with a mixture containing as little as 1% methane. Furthermore, the flame temperatures are so low that no nitric oxide is produced.

"VorTuMix"^{R} (NAO Burner Co. trademark) burners (5) are designed to handle dirty gases, such as in ground flares. A special vane configuration is used to generate a highly turbulent vortex. A two-stage combustion process minimizes NO_x formation: 10% of the air by-passes the burner throat where the rich mixture is burned at a relatively low temperature. The by-passed air is then introduced to the second stage to ensure complete combustion. These units can also burn waste gases with heat contents in the 60-200 Btu/ft^3 range. Even gases with heat content as low as 30 Btu/ft^3 could be burned with injection of some natural gas at the burner throat.

"HGE Sulzer"^{R} (Trane Thermal Co. trademark) is an example of high heat release combustor with single-unit outputs as high as 200×10^6 Btu/hr (6). Because of the extreme turbulence and high flame temperatures, the combustion is complete within the chamber and there is very little flame beyond the burner outlet (Attachment 7-7).

The "Blue Flame Isomax"™ (U. E. Corporation trademark) (7) is an example of a multi-fuel burner where the liquid fuel is converted to gas immediately prior to ignition by recirculating hot combustion gases as shown in Attachment 7-8.

In addition to the above designs, there are also:
Integral-blower burners for dryers and ovens;
Immersion-tube burners for submerged heating of liquid;
Flat-flame burners for slab heaters and glass tanks;
Hot-spot burners for spot heating by radiation and convection;
Flame-grid burners for fume destruction by direct incineration;
and a myriad of other special designs.

System Design Considerations

Energy released by combustion should be placed where it will achieve an effective heat utilization with a minimum of heat loss. One of the advantages of gaseous fuel is that the heat of combustion can be distributed with relative ease – by many small burners, a single large one, or by something in between, suitable for that particular application. The selection of the burner type and number, therefore, is tied to the application: the furnace volume, shape, and the mode of heat utilization/transfer. All these important factors are interrelated.

The characteristics of different burner types, along with special designs, were discussed in the previous section. The turndown ratio may be one of the more important requirements, but only when the need for modulation exists.

The combustion volume is the space occupied by the fuel and by the various intermediate products of combustion during burning. This volume varies considerably with fuel composition and properties, with the type of heat exchanger or vessel to be fired, and with the burner design. Generally speaking, it is desirable that the flame just fill the primary combustion volume to avoid unnecessary quenching of the oxidation reactions. A wide furnace cannot be fired properly with a single burner. A short furnace may require several smaller burners to prevent flame impingement on the rear wall.

The heat release rate with gaseous fuels is generally quite high, particularly at high mixture pressures and with thorough mixing. In the primary combustion zone, where 70 – 90% of the oxidation occurs, heat release rates of 200,000 Btu/hr-ft^3 produce good flame temperatures without the danger of flame impingement. Specially designed high intensity burners can operate quite satisfactorily at 10×10^6 Btu/hr-ft^3 levels. The overall heat release rate (for complete combustion) ranges from 30,000 to 70,000 Btu/hr-ft^3 for more conventional gas-burning installations.

The pressure against which a burner must operate is another important consideration. Furnaces normally operate at +0.01 to −1 inches of water column gauge pressure. Air leaking into the furnace is preferable – in most applications – over leakage from the combustion chamber to the ambient. However, too much vacuum could lead to excessive furnace roar and an unstable flame.

The exhaust system is yet another component deserving careful attention. It handles approximately 10 – 12 scf combustion products for each cubic foot of natural gas burned. Larger installations use either extended natural draft stacks or mechanized draft devices, with the latter becoming more common because they control gas flows better. Without mechanical draft equipment, it is extremely difficult to specify definite purge periods for start-ups and shut-downs, since the available natural draft depends on the temperature difference between the stack and the ambient, which can vary considerably. Stack temperatures below 200°F will cause corrosive condensation. Flue gas temperatures cause problems when the firing rate is low and when flue gas scrubbers or heat recovery devices are used.

Operation and Control

Safety should be the foremost consideration in operating gas-fired combustion installations. Regulations and procedures for safe operation of burners and firing-system operation have been developed by AGA, UL, FM, NFPA, as well as through local ordinances. There should always be a purge period after a flame-out, regardless of the reason. This will ensure that any combustible (explosive) mixture is eliminated from the combustion chamber before reignition is attempted. Before firing with natural gas, inspect the gas injection orifices and verify that all passages are unobstructed. Filters and moisture traps should be in place, clean, and operating effectively to prevent any plugging of gas orifices. Proper location and orientation of diffusers, spuds, gas canes, etc., should also be confirmed. Look for any burned off or missing burner parts.

Many burners will function satisfactorily under adverse conditions (particularly in cold surroundings) only if the mixture is rich and the flame is burning in free air. With burners of this type, it is necessary to leave the furnace doors open during the start-up period. If the doors are not left open, the free air in the furnace will be used up after a few seconds of operation, and the burner flame will be extinguished. Under these conditions the presence of a pilot light is a potential source of danger, because combustible gases will collect quickly after the flame has been extinguished and could be ignited—explosively—by the pilot (2).

Always consult knowledgeable personnel before attempting to switch fuel or alter the firing rate.

Proper operation of a gas-fired installation requires that the fuel rate be controlled in relation to the demand, and the air supply must be appropriate to the fuel supply. This can be accomplished either manually or by automatic control. The incoming gas supply is regulated at a constant pressure upstream of the control valve. This valve can be used to control the gas flow, based on a signal from the output of the heat exchanger. Combustion air regulation is achieved through manipulating dampers or by a special draft controller. Larger installations are likely to use more elaborate systems where the fuel and air flows are metered with automatic adjustment to compensate for any changes or disturbances.

Gaseous fuels pass through one or more fixed orifices before entering the combustion chamber. Since flow through an orifice is proportional to the square root of the pressure drop across it, small fluctuations of the upstream pressure will not have a very significant effect on the gas flow rate. However, should it be necessary to reduce the firing rate to 25% of its peak value (4-to-1 turndown), for example, a 16-fold decrease in gas pressure would be required, with the air flow-rate adjusted accordingly. This factor presents quite a control problem, particularly with firing-rate modulation in pre-mix type burners.

Failure to maintain proper air-fuel ratios can lead to operation with insufficient air or with high excess air. The most common cause of insufficient air is inadequate fresh air openings into the boiler room. Among the indicators of insufficient air are:

1. Hot, stuffy feeling in the boiler room
2. Burner pulsations
3. Extremely "rich" flame that seems to "roll" in the furnace
4. Flame front detached from the nozzle
5. Excessive gas consumption
6. Soot deposits on heat exchange surfaces
7. Smoke from the stack
8. Carbon monoxide produced by incomplete combustion.

Too high excess air is indicated by:

1. Extremely blue and "hard" (lean) flame appearance
2. Combustion roar
3. Burner vibrations or pulsations
4. Flame front blows off burner nozzle
5. Excessive gas consumption
6. Sharp, acrid odor of aldehydes and other partial oxidation products
7. Flame extinction

Flue-gas analyzers are frequently used to give an indication of combustion quality. Chemical or electrical analyzers are available for this purpose. Normal concentration ranges of combustion products in natural gas-fired installations are: 9–11% CO_2; 6-3% O_2; no CO and H_2. Attachment 7-9 shows the qualitative effect of air-fuel ratio on the flue-gas composition, as well as the results of incomplete or poor mixing. If only the flue-gas CO_2 concentration is measured, it is possible to be misled about which side of the stiochiometric air-to-fuel ratio one is operating.

Stack gas temperature in conjunction with its CO_2 concentration can be used to determine the "flue losses" and hence the approximate combustion efficiency with the help of Attachment 7-10, which has been developed for natural gas-fired installations (8).

Air Pollution Considerations

Most gaseous fuels, with the possible exception of some waste gases, are considered to be clean fuels. Pipeline-grade natural gas is virtually free of sulfur and particulates. Its combustion products do not pollute water. Natural gas transportation and distribution facilities have a minimal adverse ecological impact. However, leakage of natural gas or LNG can pose a very serious explosion hazard indeed.

The principal air contaminants from gaseous fuels, which are affected by the combustion system design and operation, are the oxidizable materials—carbon monoxide, carbon, aldehydes, organic acids, and unburned hydrocarbons. Burner design also affects the production of the oxides of nitrogen, particularly in large steam power plant boilers. The NO_x problem and techniques for controlling it are discussed in Chapter 16.

Attachments 7-11 and 7-12 give the uncontrolled emission factors for natural gas and liquefied petroleum gas (LPG), respectively (9). Nitrogen oxide emissions from these fuels are a function of the temperature in the combustion chamber and the cooling rate of the combustion products. These values vary considerably with the type and size of unit. Emissions of aldehydes are increased when there is an insufficient amount of combustion air or an incomplete mixing of the fuel and the combustion air.

It has been stated often that gas-burning installations do not produce a pollution problem. Since areas of stable flame (Attachment 7-4) cover a wide range of flow rates, often with less than 100% theoretical air, many gas-fired units have been found to operate with insufficient air resulting in high *CO* emissions (1). Typically, gas-fired units do not need as much attention from the operator as coal and fuel oil furnaces. A smoking stack of an oil-fired unit is perhaps a better indication of improper combustion. When a natural gas burning installation does smoke, or even emits a light haze, it usually has a burner problem. With atmospheric-type burners the problem is likely to have originated from a flash-back which destroyed the burner body or clogged the throat with soot.

To help alleviate the natural gas shortage, as well as reduce the pollutant emissions from gas-fired installations, efforts are now being made to increase the average seasonal efficiencies of existing gas furnaces to about 60% and for new furnaces to approximately 85%. These gains in efficiency could be achieved by retrofitting existing furnaces with components such as advanced burners, improved heat exchangers and heat pipes, and by replacing old furnaces with pulse-combustion units or condensing furnaces.

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4. Waid, D. E., "Energy from Waste Gases," *Chem. Eng. Progress*, Vol. 74, No. 5, 77-80 (1978).
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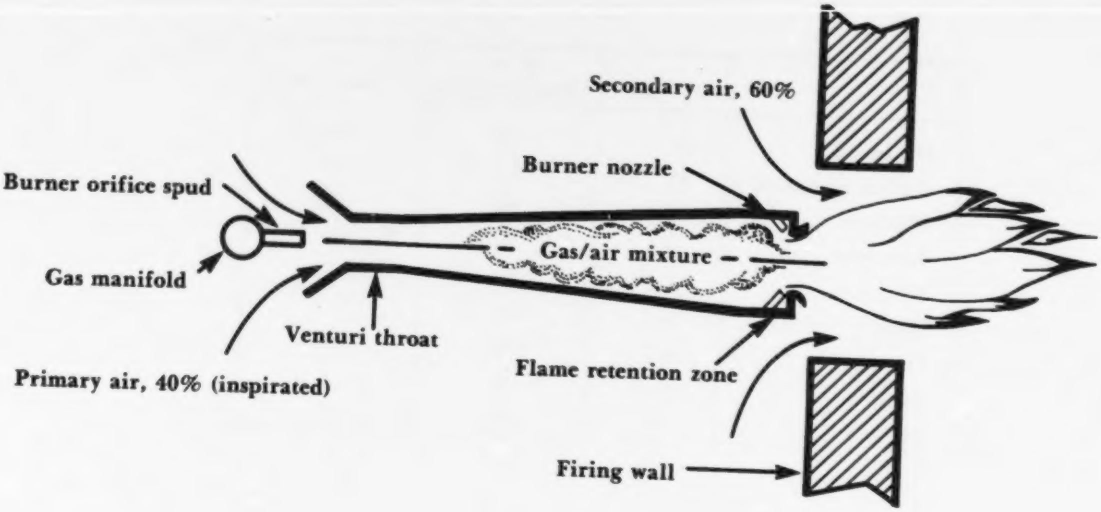
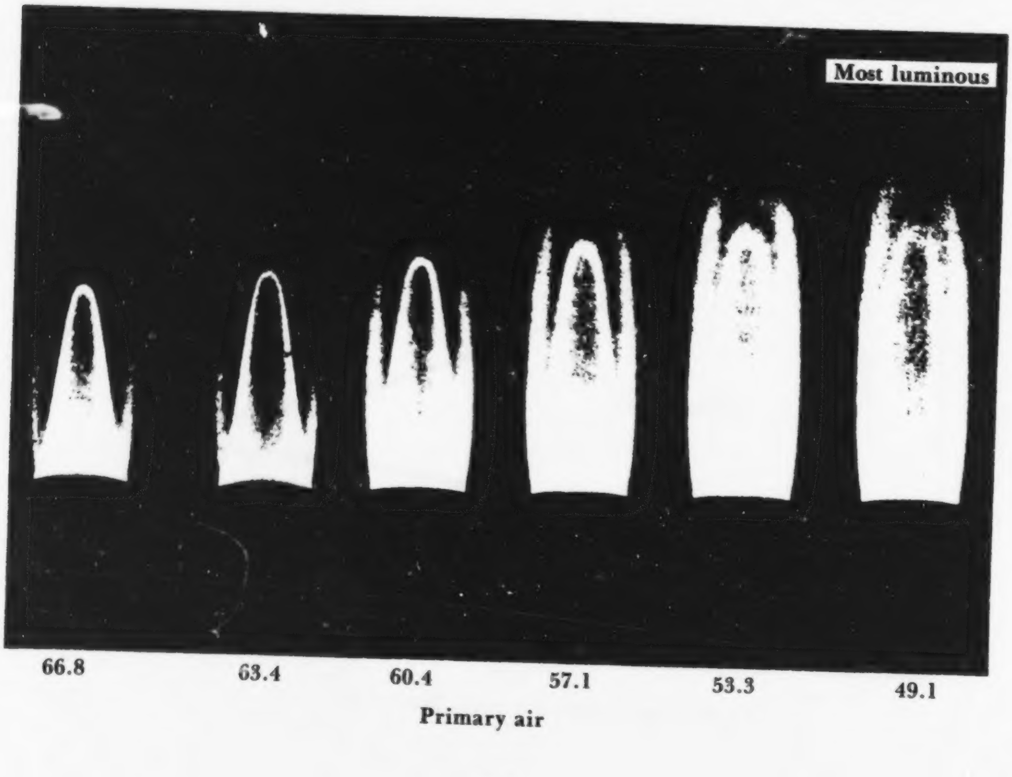
6. "Industrial Burners," The Trane Thermal Company, Conshocken, PA, Bulletin No. 143-A (1976).
7. "Blue Flame Multi-Fuel Burner," U. E. Corporation, Ringoes, NJ, Bulletin 475 (1976).
8. Jaeger, K. S., "Natural Gas Fired Installations—Design Considerations," unpublished paper, Forney Engineering Company, Dallas, TX.
9. "Compilation of Air Pollution Emission Factors," AP-42, Third Edition, USEPA (August 1977).

Attachment 7-1. Atmospheric premix-type gas burner


Secondary air, 60%
Burner nozzle
Burner orifice spud
Gas/air mixture
Gas manifold
Venturi throat
Primary air, 40% (inspirated)
Flame retention zone
Firing wall

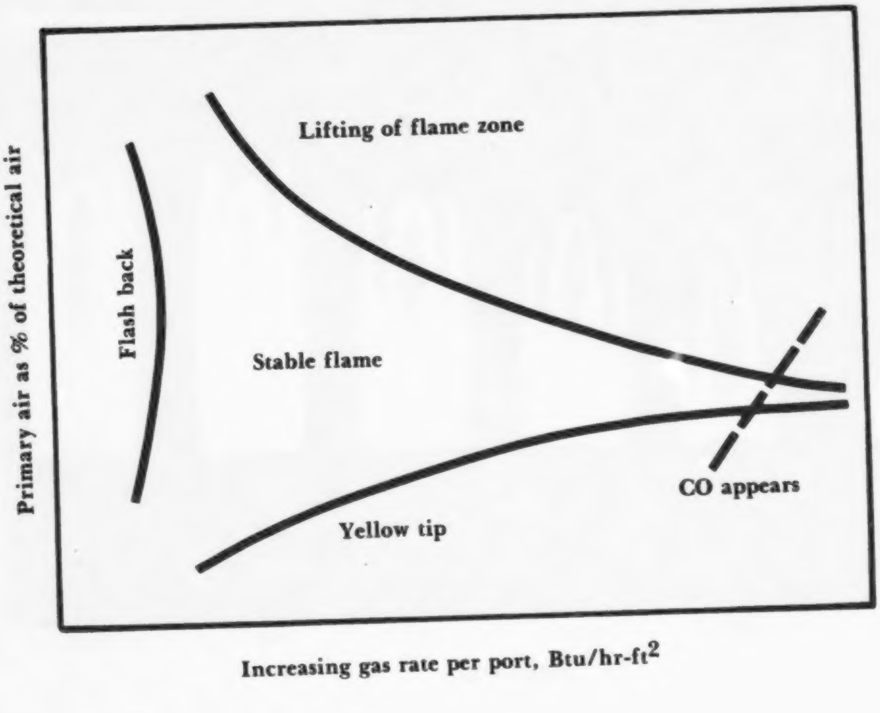
Attachment 7-2. Natural gas flames with varying primary air[1]


Most luminous
66.8
63.4
60.4
57.1
53.3
49.1
Primary air

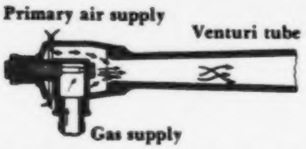
Attachment 7-3. Composition and flame propagation for maximum-speed mixtures with small burner tubes[3]

	% Gas	% of Theoretical Air	V flame, cm/s
Hydrogen	42	58	225
Carbon monoxide	45	50	43
Methane	9.8	95	37
Acetylene	9.5	80	145
Ethylene	7.2	90	70
Ethane	6.4	87	
Propane	4.7	85	45
Butane	3.65	85	
Pentane	2.9	88	35

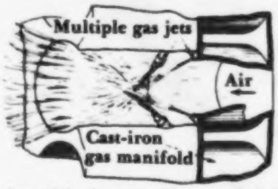
Attachment 7-4. Atmospheric burners—flame stability



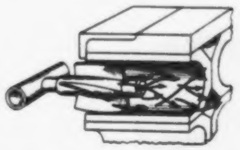
Attachment 7-5. Selected gas burner types


Primary air supply
Venturi tube
Gas supply

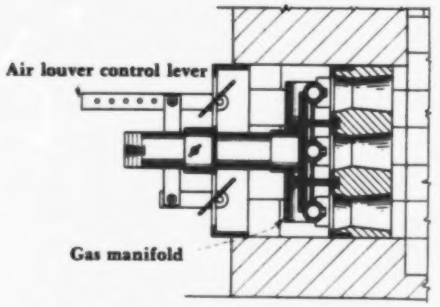
1. Atmospheric gas burners pull in their primary air for combustion by the action of a stream of low-pressure gas expanding through an orifice.


Multiple gas jets
Air
Cast-iron gas manifold

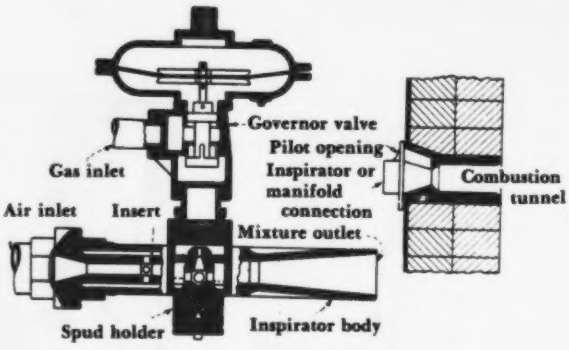
2. Premixing of fuel gas and air needed for combustion takes place in a mixing chamber outside the furnace proper.



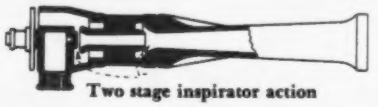
3. Vanes placed in the path of incoming air to this tunnel burner act to impart swirling motion to stream.


Air louver control lever
Gas manifold

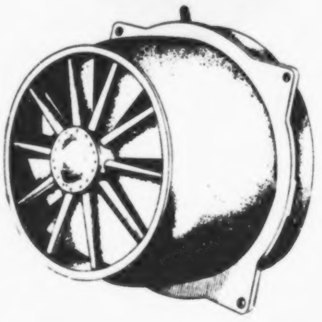
4. Gas issues from a number of spuds connecting to vertical and horizontal manifolds. Primary air enters around the spuds.


Governor valve
Pilot opening
Gas inlet
Inspirator or manifold connection
Combustion tunnel
Air inlet
Insert
Mixture outlet
Spud holder
Inspirator body

5. So called low-pressure gas-burner systems work with air under pressure and gas at atmospheric conditions. An inspirator governor, left above, delivers gas-air mixture at proper pressure to burner blocks, right above.

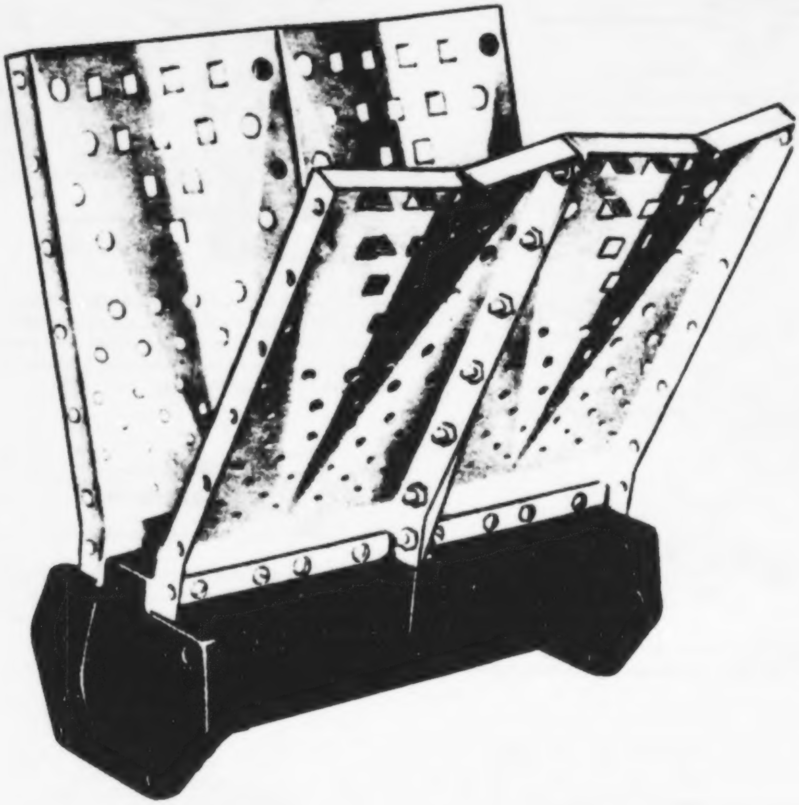

Two stage inspirator action

6. Two-stage burner operates on high-pressure gas; passes it through two venturi sections in series. Primary air enters shutter, at left, under induction.

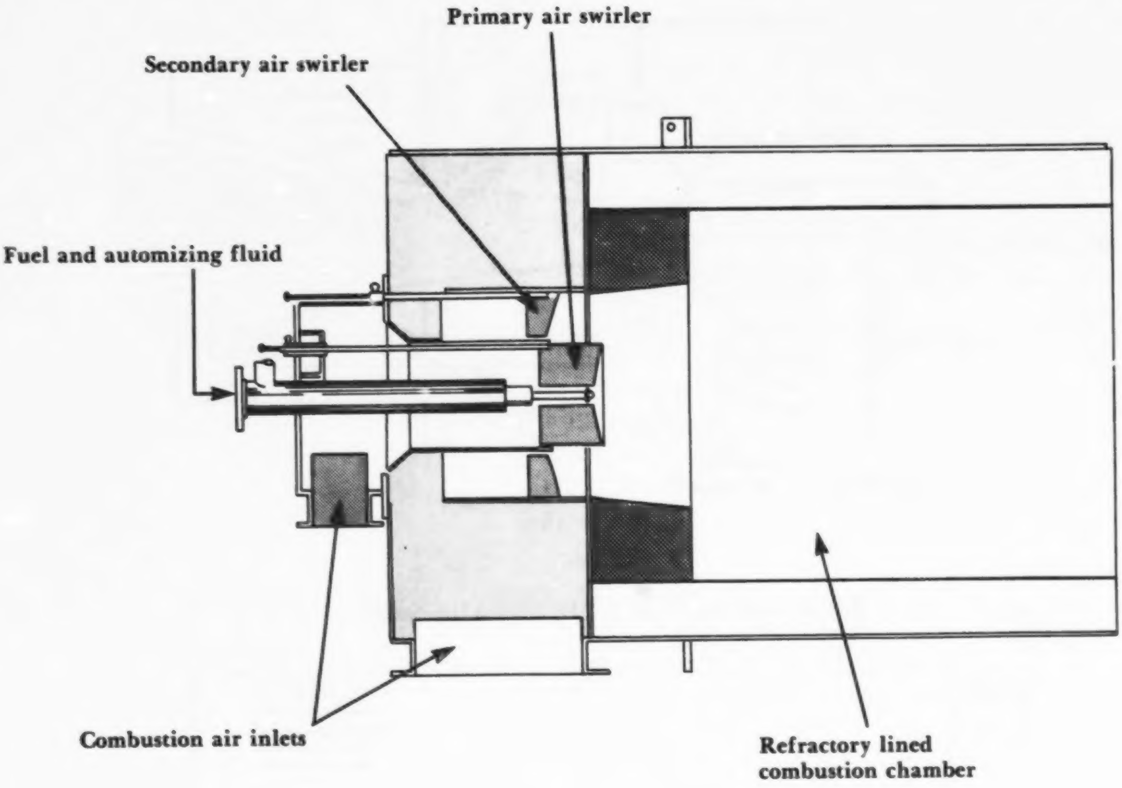


7. High-pressure gas issues from jets in the spider and reaction spins the spider to rotate the fan. Resulting turbulence gives prompt, thorough mixing.

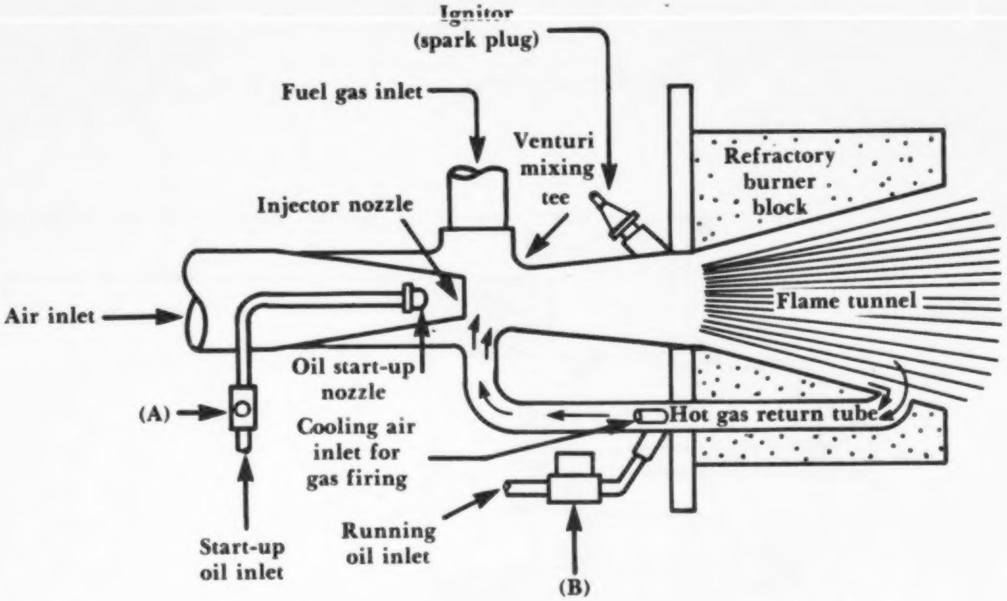
Attachment 7-6. Mixing plate burner (Maxon Corp., Muncie, IN)[1]



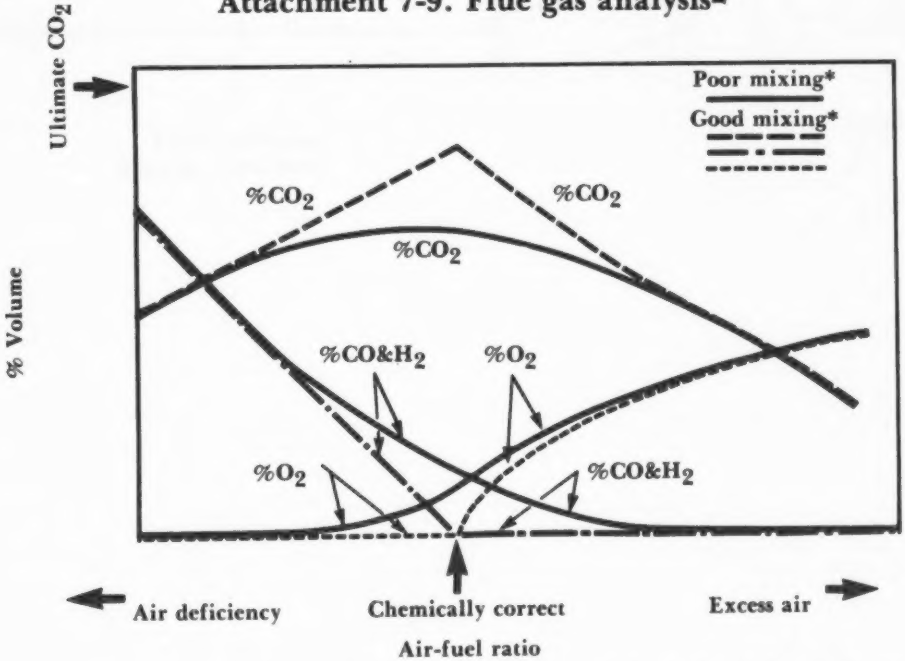
Attachment 7-7. HGE Sulzer combustion burner (Trane Thermal Co., Conshohocken, PA)[6]


Primary air swirler
Secondary air swirler
Fuel and automizing fluid
Combustion air inlets
Refractory lined
combustion chamber

Attachment 7-8. Multi-fuel oil gasifying burner (U. E. Corp., Ringoes, NJ)[7]

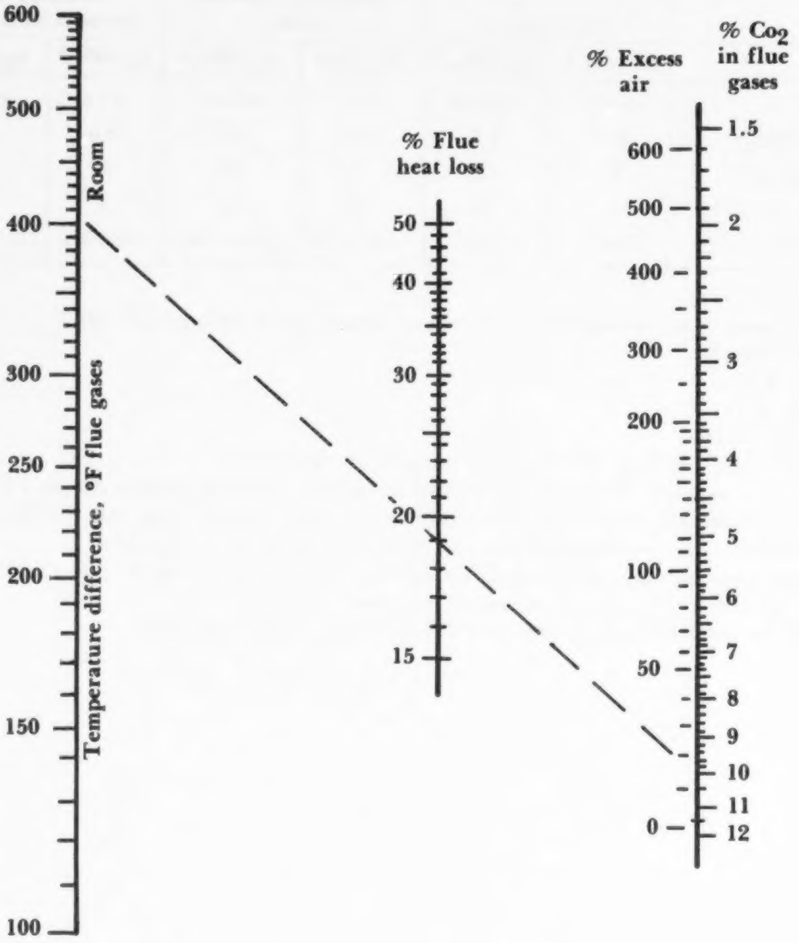

Ignitor (spark plug)
Fuel gas inlet
Venturi mixing tee
Refractory burner block
Injector nozzle
Air inlet
Flame tunnel
Oil start-up nozzle
(A)
Cooling air inlet for gas firing
Hot gas return tube
Running oil inlet
Start-up oil inlet
(B)

Attachment 7-9. Flue gas analysis[2]



*Note: The differences between poor and good mixing of the fuel and air are shown by the solid and broken lines, respectively. This chart is for qualitative comparisons only; hence no numerical values are shown.

Attachment 7-10. Flue heat losses with natural-gas-fired installations[8]



Note: Average dew-point for flue gas products of natural gas combustion is 178°F.

Example: Heat loss for flue gases at 400°F temperature difference above room and 10% CO_2 is found to be 19%. Therefore, the combustion efficiency is 81%.

Attachment 7-11. Emission factors for natural gas combustion emission factor rating: A[9]

	Type of unit					
	Power plant		Industrial process boiler		Domestic and commercial heating	
Pollutant	$lb/10^6ft^3$	$kg/10^6m^3$	$lb/10^6ft^3$	$kg/10^6m^3$	$lb/10^6ft^3$	$kg/10^6m^3$
Particulates[a]	5-15	80-240	5-15	80-240	5-15	80-240
Sulfur oxides (SO_2)[b]	0.6	9.6	0.6	9.6	0.6	9.6
Carbon monoxide[c]	17	272	17	272	20	320
Hydrocarbons (as CH_4)[d]	1	16	3	48	8	128
Nitrogen oxides (NO_2)[e]	700[f-h]	11,200[f-h]	(120-230)[i]	(1920-3680)[i]	(80-120)[j]	(1280-1920)[j]

[a] References 4, 7, 8, 12.

[b] Reference 4 (based on an average sulfur content of natural gas of 2000 $gr/10^6$ $stdft^3$ (4600 $g/10^6Nm^3$).

[c] References 5, 8-12.

[d] References 8, 9, 12.

[e] References 3-9, 12-16.

[f] Use 300 $lb/10^6$ $stdft^3$ (4800 $kg/10^6$ Nm^3) for tangentially fired units.

[g] At reduced loads, multiply this factor by the load reduction coefficient given in Figure 1.4-1.

[h] See text for potential NO_x reductions due to combustion modifications. Note that the NO_x reduction from these modifications will also occur at reduced load conditions.

[i] This represents a typical range for many industrial boilers. For large industrial units (>100 MMBtu/hr) use the NO_x factors presented for power plants.

[j] Use 80 (1280) for domestic heating units and 120 (1920) for commercial units.

Attachment 7-12. Emission factors for LPG combustion[a], emission factor rating: C[9]

Pollutant	Industrial process furnaces				Domestic and commercial furnaces			
	Butane		Propane		Butane		Propane	
	lb/10^3 gal	kg/10^3 ℓ	lb/10^3 gal	kg/10^3 ℓ	lb/10^3 gal	kg/10^3 ℓ	lb/10^3 gal	kg/10^3 ℓ
Particulates	1.8	0.22	1.7	0.20	1.9	0.23	1.8	0.22
Sulfur oxides[b]	0.09S	0.01S	0.09S	0.01S	0.09S	0.01S	0.09S	0.01S
Carbon monoxide	1.6	0.19	1.5	0.18	2.0	0.24	1.9	0.23
Hydrocarbons	0.3	0.036	0.3	0.036	0.8	0.096	0.7	0.084
Nitrogen oxides[c]	12.1	1.45	11.2	1.35	(8.12)[d]	(1.0 to 1.5)[d]	(7 to 11)[d]	(0.8 to 1.3)[d]

[a] LPG emission factors calculated assuming emissions (excluding sulfur oxides) are the same, on a heat input basis, as for natural gas combustion.

[b] S equals sulfur content expressed in grains per 100 ft^3 gas vapor; e.g., if the sulfur content is 0.16 grain per 100 ft^3 (0.366 g/100 m^3) vapor, the SO_2 emission factor would be 0.09 × 0.16 or 0.014 lb SO_2 per 1000 gallons (0.01 × 0.366 or 0.0018 kg $SO_2/10^3$ liters) butane burned

[c] Expressed as NO_2.

[d] Use lower value for domestic units and higher value for commercial units.

Chapter 8

Fuel Oil Burning

Introduction to Oil Combustion

The overall purpose of fuel burning is to generate hot combustion gases in a useful, efficient, and environmentally acceptable manner. This is achieved typically by burning the fuel completely, with a minimum practical quantity of air, and by discarding the flue gas at a reasonably low temperature.

The rate of combustion of a liquid fuel is limited by vaporization. Light distillate oils (such as kerosene, No. 1 fuel oil) readily vaporize in simple devices. Other fuel oils, because of their heavier composition, require more complicated equipment to assure vaporization and complete combustion.

In order to achieve complete combustion, oils are atomized into small droplets for rapid vaporization. The rate of evaporation is dependent on surface area, which is greater as the atomized droplet size is smaller (for a given quantity of oil). Atomization size distribution varies with the type of burner, as illustrated in Attachment 8-1. The desired shape of the atomization pattern (hollow cone, solid cone, etc.), as well as the droplet sizes, are influenced adversely if fuel viscosity is improper or if the nozzles become carbonized, clogged, eroded, or cracked.

Viscosity is a measure of the fluid's internal resistance to flow. It varies with fuel composition and temperature, as was illustrated in Chapter 3, Attachment 3-6. At ambient temperature, No. 2 fuel oil may be atomized properly, but typically No. 6 fuel oil must be heated to around 210°F to assure proper atomization. No. 5 may require heating to 185°F and No. 4 to 135°F.

Dirt and foreign matter suspended in the oil may cause wear in the oil pump and blockage of the atomizing nozzles. Strainers or replaceable filters are required in the oil suction line, as well as in the discharge line. Some burners may have a fine mesh screen or a porous plug-type filter to prevent nozzle damage and the resulting poor droplet atomization. Other systems may have pumps with design features to collect particles of foreign matter and to mechanically reduce their size to minute particles which flow through the pump, filter, and nozzle (1).

Proper mixing of droplets with air, a continuous source of ignition, and adequate time to complete combustion (before the hot gases are quenched on the furnace surfaces) are other requirements. However, if too much uneven mixing or turbulence is present in the flame zone, hot spots may occur which will result in higher NO_X emissions.

During combustion of a distillate fuel oil, the droplet becomes uniformly smaller as it vaporizes. By contrast, a residual oil droplet undergoes thermal and catalytic cracking, and its composition and size undergoes various changes with time. Vapor bubbles may form, grow, and burst within a droplet in such a way as to shatter the droplet as it is heated in the combustion zone. If adequate time and temperature are not available for complete combustion, carbonaceous materials (soot) may be deposited on metal surfaces or be emitted with smoke.

Oil Burning Equipment

Oil burning furnaces or boilers are classified typically as either domestic, commercial, industrial, or utility-sized units. Although the limits which separate the size designations are not clearly established, each group has important characteristics. As displayed in Attachment 8-2, small residential heating units use considerably more excess air and burn with a much shorter residence time than the larger units. The larger volumetric heat release rate of the smaller sized units results from the favorable area-to-volume ratio for small units. As units of larger size are considered, special heat transfer design provisions are required for adequate energy extraction.

Domestic oil burners typically burn No. 2 fuel oil at a rate of between 0.5 and 3 gph (gallons per hour). These units are mass-produced packages which include the combustion air fan, oil pump, gun or nozzle assembly, and transformer with ignition electrodes. Typical domestic units have simple automatic combustion control features, with around 40% excess air required for complete combustion. These units should have the oil filter cleaned or replaced and the nozzle replaced at least annually.

Commercial-sized oil burners typically burn No. 4, 5, or 6 fuel oil at a rate of between 3 and 100 gph. Although electric heating of oil is typical, steam may be used. These units may also burn No. 2 fuel oil. Around 30% excess air is provided for complete combustion. An example of a commercial-sized oil unit would be that of a Scotch marine (fire tube) boiler shown in Attachment 8-3. Commercial-sized units may also be designed as integral furnace (water-wall) heaters or boilers.

Industrial-sized oil-fired furnaces or boilers typically burn No. 4, 5, or 6 fuel oil at a rate of 70 to 3,500 gph. These units may be constructed either at the site or in a factory, depending on the size. Generally steam is produced for purposes such as process heating, space heating, and electric generation. Combustion occurs with around 15% excess air. One example of an industrial-sized furnace is that of a D-type integral furnace boiler as shown in Attachment 8-4. Many units are capable of burning either oil or gas.

Utility boilers which are oil fired burn No. 6 fuel oil, Bunker C, at rates of 3,500 to 60,000 gph. These are large installations having proper combustion-control systems and maintenance for maximum efficiency with combustion at around 3% excess air.

Examples of Burners

A large number of oil burner (atomizer) designs have been developed to meet objectives such as economy, durability, and reliability in providing the atomization or flame requirements of the various furnace designs. Examples of burners are presented in the following paragraphs.

A high-pressure atomizer for domestic applications is illustrated in Attachment 8-5. Units of this type may burn No. 2 fuel oil (0.5 to 30 gph) at oil pressures of 100 psi. Note the cone nozzle and swirl vanes which provide an increase in air/fuel mixing. Electrodes provide a continuous source of ignition. Control of the oil pump, typically, is by a thermostatically controlled on/off switch. High-pressure atomizers for commercial and industrial applications may burn No. 4 or 5 fuel oil (up to 200 gph) with oil pressure up to 300 psi.

A low-pressure air atomizer is illustrated in Attachment 8-6. In domestic applications, No. 2 fuel oil is burned (0.5 to 6 gph) with oil and air pressures around 3 psi. Note the tangential air passages which produce swirl of primary air prior to impacting film of oil. In commercial applications No. 4 and 5 fuel oils also may be burned (5 to 150 gph) with air and oil pressures from 12 to 50 psi.

Steam or air atomizers for commercial, industrial, and utility applications (up to 1,100 gph) may have oil pressure up to 1,000 psi and steam pressure 20 to 40 psi greater than oil pressure. The burners may be external mixing with a typical atomization cone and flame (see Attachment 8-7) or internal mixing with a short, bushy flame (see Attachment 8-8). If steam is used, a steam trap is provided to remove condensate which would cause nozzle erosion.

Mechanical atomizers, with provisions for firing control by return-flow (spill-back) pressure regulation, are illustrated in Attachments 8-9 and 8-10. Oil pressure may vary from 450 to 1,000 psi in typical industrial and utility applications with a fuel rate up to 1,250 gph.

The horizontal rotary cup oil burner was formerly in widespread use. However, as was indicated in Attachment 8-1, the droplet sizes formed are considerably larger than for other burners. Smoking tendencies have resulted in sources changing to burners of other designs. In the rotary cup, as illustrated in Attachment 8-11, an oil film inside a hollow cup (spinning at around 3,500 rpm) is subjected to centrifugal forces which cause the atomization. If the cup becomes eroded or cracked, atomization quality deteriorates.

Factors Influencing Air Pollutants from Oil Combustion

The properties of the oil and the characteristics of the combustion equipment influence the air pollution emissions from stationary sources. Air pollutant emission factors for oil combustion are presented in Attachment 8-12.

The emission factors for sulfur oxides (expressed as lb./1,000 gal.) depend primarily on the sulfur content and to a lesser extent on the type of fuel (distillate or residual, because of their different densities).

Nitrogen oxide emission factors are larger for larger combusion installations. This is dependent upon the combustion temperature and nitrogen composition in the fuel, both of which are more favorable with smaller installations.

Fuel oil has a small ash composition from a trace amount in No. 2 to 0.08% in No. 6. Particulate emissions depend on the completeness of combustion as well as the ash content. The emission factor for particulate emissions from residual oil burning is related to the sulfur content. This results from the fact that lower sulfur No. 6 fuel oil typically has substantially lower viscosity and reduced asphatene and ash content. Consequently, lower sulfur fuel oils atomize and burn easier. This applies regardless of whether the fuel oil is refined from naturally occurring low-sulfur crudes or is desulfurized by current refinery practice.

The vanadium content in fuel oil may be deposited in the ash on boiler metallic surfaces. These deposits act catalytically in converting SO_2 to SO_3, thereby creating dew-point and acid smut problems. Oil-fired burners may emit acid smuts (particulates) which fall out near the stack and stain or etch painted surfaces. Acid smuts may be caused by the metallic surfaces operating well below the acid dew-point of the flue gas with soot absorbing sulfuric acid vapor. Switching to a negligible vanadium content fuel may reduce the conversion of SO_2 to SO_3 and thereby avoid the acid smut problem.

Both sodium and vanadium from fuel oil may form sticky ash compounds having low melting temperatures. These compounds increase the deposition of ash (fouling heat exchange surfaces) and are corrosive. Soot blowing should be frequent enough so that ash deposits cannot build up to a thickness where the surface becomes molten and thereby difficult to clean.

Fuel oil additives, such as alumina, dolomite, and magnesia, have been found effective in reducing superheater fouling, high-temperature ash corrosion, and low-temperature ash corrosion. Additives may either produce high melting point ash deposits (which do not fuse together) or form refractory sulfates which are easily removed in soot-blowing.

Other fuel oil additives may reduce smoke and particulate emissions. Organometallic compounds of manganese, iron, nickel, cobalt, barium, and calcium have a catalytic influence either on oxidation of soot or on the promotion of free radicals which react with soot.

Maintenance of atomizing nozzles includes removing them from the furnace, cleaning them to remove deposits and foreign materials, and inspecting them for wear or cracks. A major installation may require maintenance of nozzles during each eight-hour shift. On the other hand, a small residential installation may require nozzle replacement and strainer cleaning only once a year. Poor atomization results in flames which are longer and darker and which increase the soot or slag buildup on furnace walls. Soot or slag act as insulators and thereby reduce the heat transfer efficiency.

Draft is the negative pressure difference between the inside of the furnace (or stack) and the outside. If draft is too high the hot gases are accelerated too fast with inadequate residence time for complete combustion.

If stack draft is too low, adequate pressure drop may not be available to pull the gases across the convection breeching. If furnace pressure becomes greater than atmospheric, cooling air is no longer drawn in through various cracks and apertures, and there is outward movement of hot gases, quenching of combustion gases, and overheating of the furnace structure.

Draft should be set at original design value for proper residence time, air/fuel mixing, and settling velocities for blown soot.

Poor ignition and unstable flames can cause smoke. Ignition provisions vary with fuel and atomizer type. A domestic unit firing No. 2 fuel oil may have a continuous spark between two electrodes which is driven by a 7,000 to 10,000-volt transformer. By contrast, a utility or industrial unit may have a fully programmed staging sequence which uses pilot, auxiliary fuel igniters, staged burner controls, and safety interlocks (which may use optical, pressure, or temperature-sensing equipment).

Smoking may occur during a cold start unless the design provides for adequate ignition energy and controlled delivery and mixing of the fuel and air. Ignition energy must compensate for the extra high heat loss to the cold combustion chamber. In order to reduce smoke and reduce furnace damage due to thermal shock, some systems provide for slow heating of combustion chamber prior to full fuel firing rate.

The U. S. Environmental Protection Agency has published adjustment procedures for packaged industrial, commercial, and domestic units (5, 6, 7). These procedures will be discussed in Chapter 17.

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1. Burkhardt, C. H., *Domestic and Commercial Oil Burners*, Third Edition, McGraw-Hill Book Co., New York (1969).
2. Fryling, G. R., *Combustion Engineering*, Revised Edition, published by Combustion Engineering, Inc., New York (1966).
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4. Reed, R. D., *Furnace Operations*, Second Edition, Gulf Publishing Co., Houston (1976).
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6. "Guidelines for Burner Adjustments of Commercial Oil-Fired Boilers," EPA-600/2-76-088, published by Industrial Env. Res. Lab, USEPA (March 1976).
7. "Guidelines for Industrial Boiler Performance Improvement," EPA-600/8-77/003a, published by Industrial Env. Res. Lab, USEPA (January 1977).
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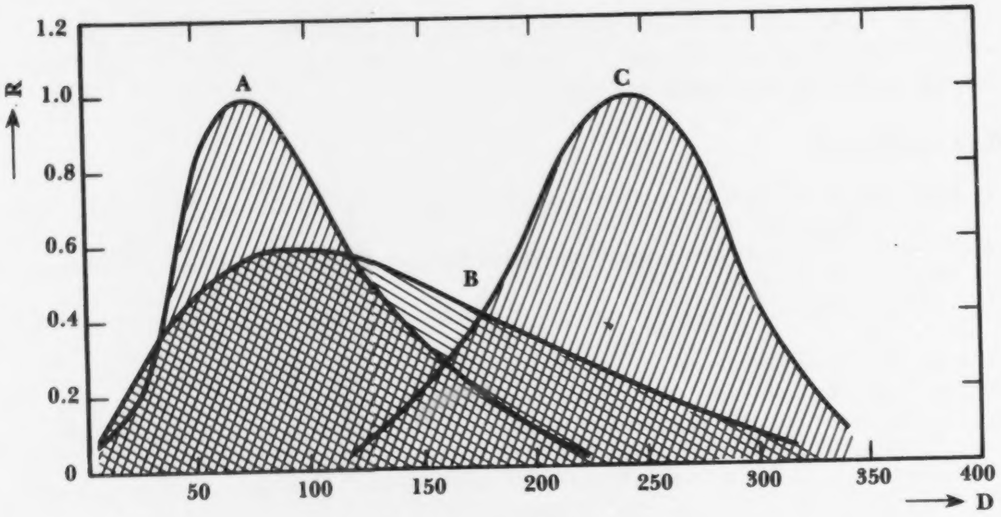
9. "Commercial and Industrial Fuel Oil Equipment and Its Preventive Maintenance," Publication No. 67-100, National Oil Fuel Institute, Washington, DC (1967).
10. Johnson, A. J., and Auth, G. H., *Fuels and Combustion Handbook*, McGraw-Hill Book Co. (1951).
11. Compilation of Air Pollutant Emission Factors, 3rd Edition, AP-42, Part A, U. S. Environmental Protection Agency, (1977).

Attachment 8-1. Atomizing characteristics of different burners—distributions of droplet size

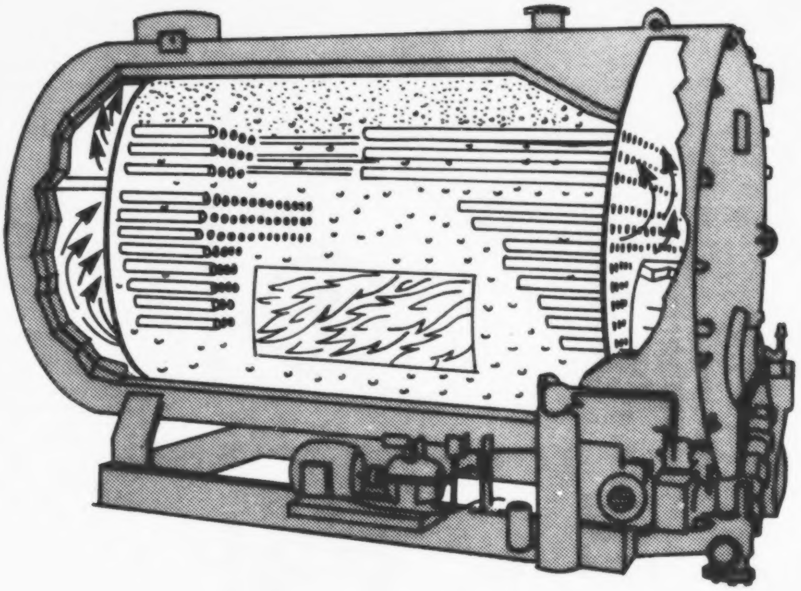


A = steam atomizing
B = pressure-jet atomizing
C = rotary cup atomizing

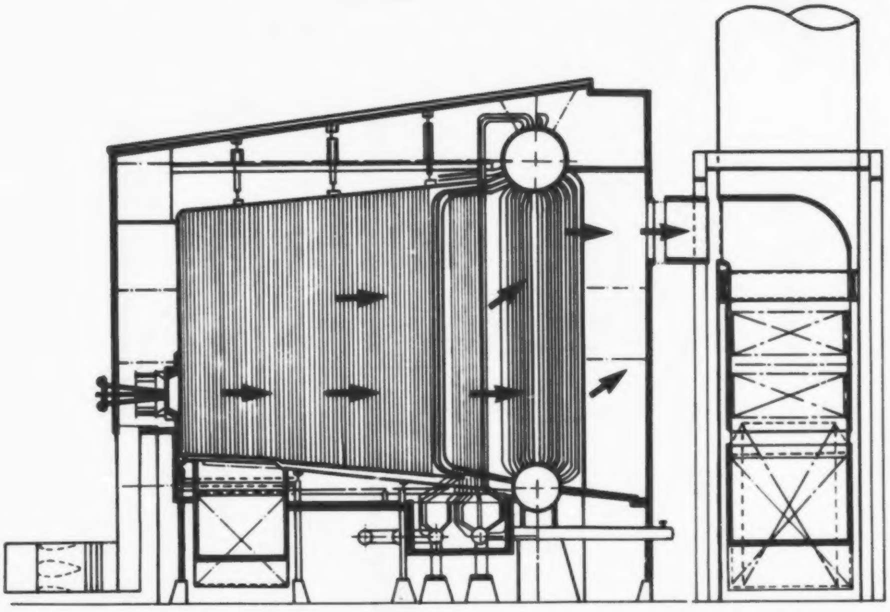
Attachment 8-2. Typical oil combustion design parameters[8]

Unit Type	Heat Input Million Btu/hr	Excess Air, %	CO_2	Volumetric Heat Release Btu/hr ft^3	Residence Time Sec.
Home heat	0.18	40	11	340,000	0.13
Apartment boiler	2.2	27	13	100,000	0.50
Ship's boiler	80	15	14	70,000	0.80
60 MW power station	600	3	15.7	20,000 to 40,000	2.2 to 1.1

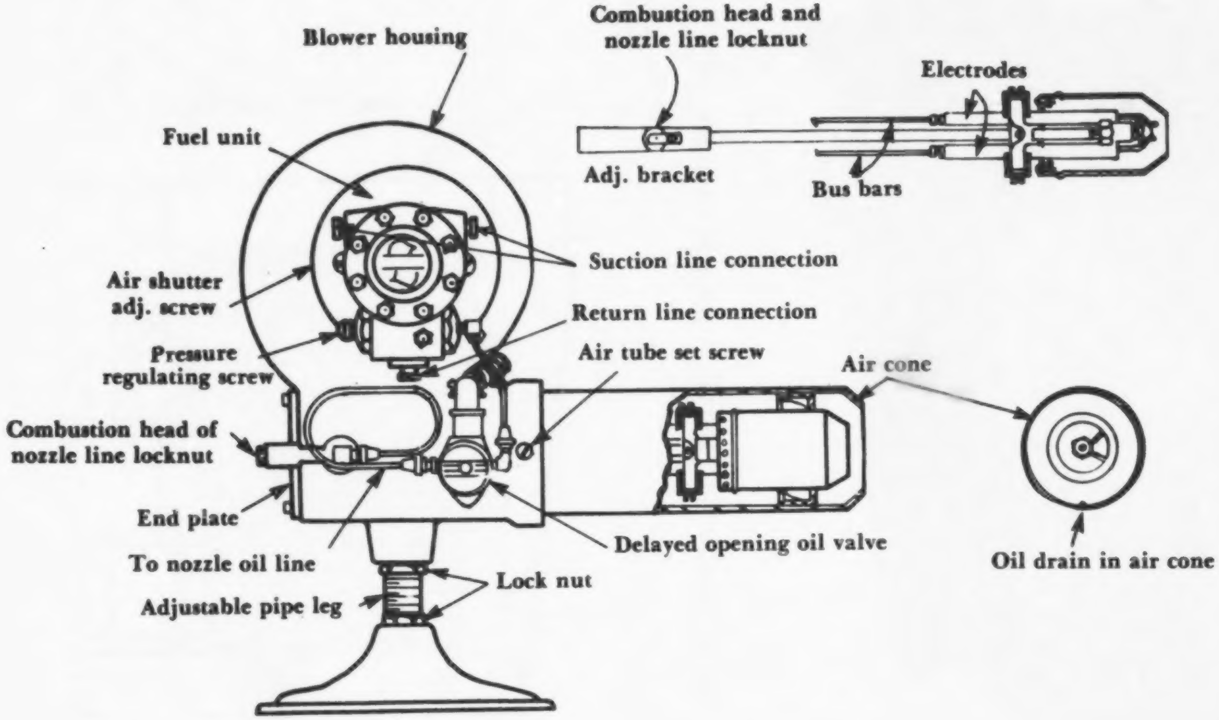
Attachment 8-3. Scotch-marine (fire-tube) boiler



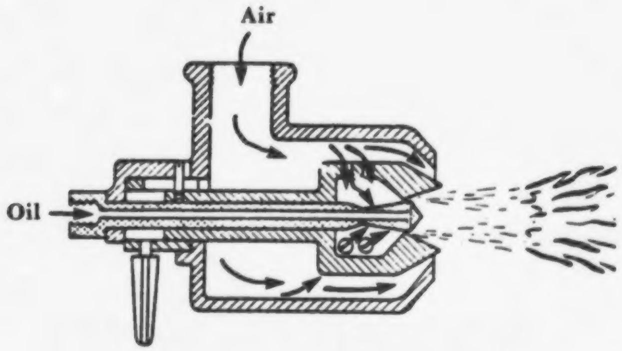
Attachment 8-4. D-type integral furnace boiler



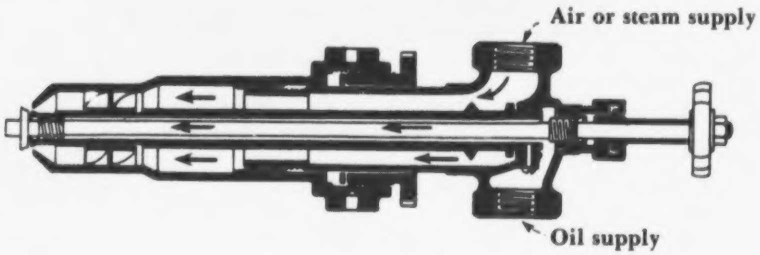
Attachment 8-5. Typical pressure atomizing #2 oil burner[9]


Blower housing
Combustion head and nozzle line locknut
Electrodes
Fuel unit
Adj. bracket
Bus bars
Suction line connection
Air shutter adj. screw
Return line connection
Pressure regulating screw
Air tube set screw
Air cone
Combustion head of nozzle line locknut
End plate
Delayed opening oil valve
Oil drain in air cone
To nozzle oil line
Lock nut
Adjustable pipe leg

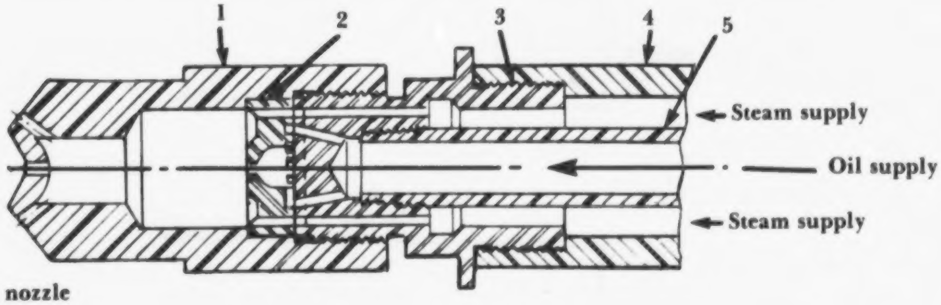
Attachment 8-6. Low-pressure, air-atomizing oil burner[8]



Attachment 8-7. External mix stream or air-atomizing burner[9]

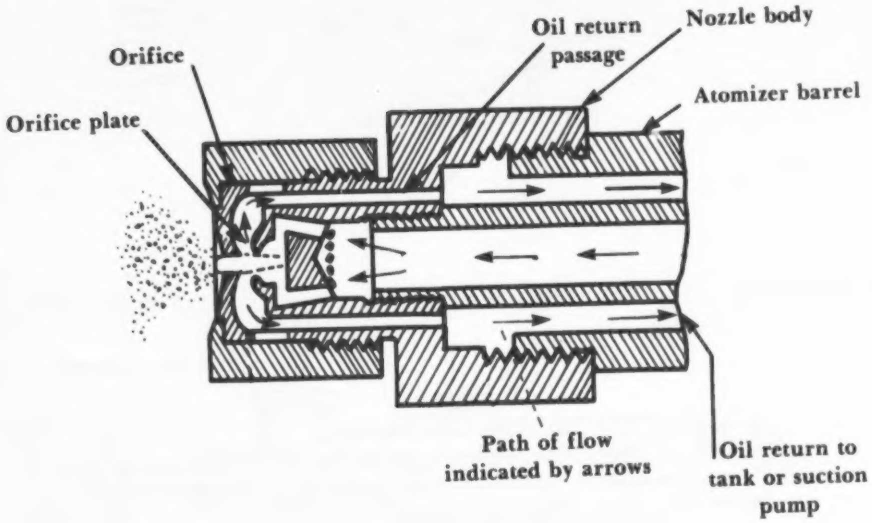

Air or steam supply
Oil supply

Attachment 8-8. Internal mix steam-atomizing burner[9]

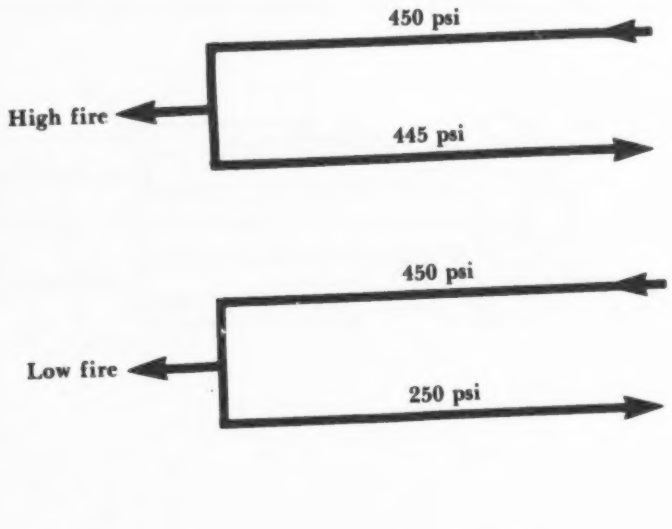

1
2
3
4
5
Steam supply
Oil supply
Steam supply

1. Mixing nozzle
2. Sprayer plate
3. Nozzle body
4. Atomizer barrel
5. Inlet tube

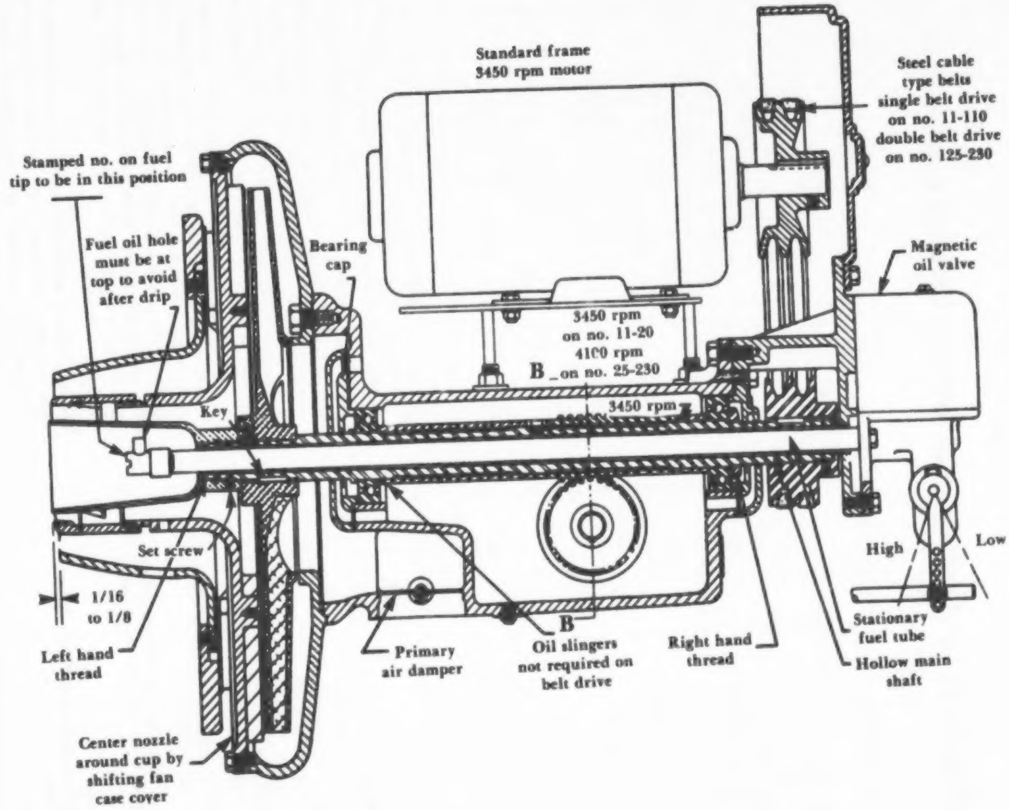
Attachment 8-9. Mechanical atomizer, return-flow type[10]


Orifice
Orifice plate
Oil return passage
Nozzle body
Atomizer barrel
Path of flow indicated by arrows
Oil return to tank or suction pump

Attachment 8-10. Example pressures for return-flow type mechanical atomization[10]


450 psi
High fire
445 psi
450 psi
Low fire
250 psi

Attachment 8-11. Typical rotary cup burner[9]


Standard frame
3450 rpm motor
Steel cable type belts single belt drive on no. 11-110 double belt drive on no. 125-230
Stamped no. on fuel tip to be in this position
Fuel oil hole must be at top to avoid after drip
Bearing cap
Magnetic oil valve
3450 rpm on no. 11-20
4100 rpm on no. 25-230
B
3450 rpm
Key
Set screw
High
Low
1/16 to 1/8
Left hand thread
Primary air damper
B
Oil slingers not required on belt drive
Right hand thread
Stationary fuel tube
Hollow main shaft
Center nozzle around cup by shifting fan case cover

Attachment 8-12. Emission factors for fuel oil combustion

	Type of boiler[a]							
	Power plant		Industrial and commercial				Domestic	
	Residual oil		Residual oil		Distillate oil		Distillate oil	
Pollutant	lb/10^3 gal	kg/10^3 liter	lb/10^3 gal	kg/10^3 liter	lb/10^3 gal	kg/10^3 liter	lb/10^3 gal	kg/10^3 liter
Particulate[b]	c	c	c	c	2	0.25	2.5	0.31
Sulfur dioxide[d]	157S	19S	157S	19S	142S	17S	142S	17S
Sulfur trioxide[d]	2S	0.25S	2S	0.25S	2S	0.25S	2S	0.25S
Carbon monoxide[e]	5	0.63	5	0.63	5	0.63	5	0.63
Hydrocarbons (total, as CH_4)[f]	1	0.12	1	0.12	1	0.12	1	0.12
Nitrogen oxides (total, as NO_2)[g]	105(50)[h,i]	12.6(6.25)[h,i]	60[j]	7.5[j]	22	2.8	18	2.3

[a] Boilers can be classified, roughly, according to their gross (higher) heat input rate, as shown below.

Power plant (utility) boilers: $>250 \times 10^6$ Btu/hr
($>63 \times 10^6$ kg-cal/hr)
Industrial boilers: $>15 \times 10^6$, but $<250 \times 10^6$ Btu/hr
($>3.7 \times 10^6$, but $<63 \times 10^6$ kg-cal/hr)
Commercial boilers: $>0.5 \times 10^6$, but $<15 \times 10^6$ Btu/hr
($>0.13 \times 10^6$, but $<3.7 \times 10^6$ kg-cal/hr)
Domestic (residential) boilers: $<0.5 \times 10^6$ Btu/hr
($<0.13 \times 10^6$ kg-cal/hr)

[b] Based on References 3 through 6. Particulate is defined in this section as that material collected by EPA Method 5 (front half catch)[7].

[c] Particulate emission factors for residual oil combustion are best described, on the average, as a function of fuel oil grade and sulfur content, as shown below.

Grade 6 oil: lb/10^3 gal = 10 (S) + 3
[kg/10^3 liter = 1.25 (S) + 0.38]
Where: S is the percentage, by weight, of sulfur in the oil
Grade 5 oil: 10 lb/10^3 gal (1.25 kg/10^3 liter)
Grade 4 oil: 7 lb/10^3 gal (0.88 kg/10^3 liter)

[d] Based on References 1 through 5. S is the percentage, by weight, of sulfur in the oil.

[e] Based on References 3 through 5 and 8 through 10. Carbon monoxide emissions may increase by a factor of 10 to 100 if a unit is improperly operated or not well maintained.

[f] Based on References 1, 3 through 5, and 10. Hydrocarbon emissions are generally negligible unless unit is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

[g] Based on References 1 through 5 and 8 through 11.

[h] Use 50 lb/10^3 gal (6.25 kg/10^3 liter) for tangentially fired boilers and 105 lb/10^3 gal (12.6 kg/10^3 liter) for all others, at full load, and normal (>15 percent) excess air. At reduced loads, NO_x emissions are reduced by 0.5 to 1 percent, on the average, for every percentage reduction in boiler load.

[i] Several combustion modifications can be employed for NO_x reduction: (1) limited excess air firing can reduce NO_x emissions by 5 to 30 percent, (2) staged combustion can reduce NO_x emissions by 20 to 45 percent, and (3) flue gas recirculation can reduce NO_x emissions by 10 to 45 percent. Combinations of the modifications have been employed to reduce NO_x emissions by as much as 60 percent in certain boilers. See section 1.4 for a discussion of these NO_x-reducing techniques.

[j] Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly dependent on the fuel nitrogen content and can be estimated more accurately by the following empirical relationship:

lb NO_2/10^3 gal = 22 + 400 $(N)^2$
[kg NO_2/10^3 liters = 2.75 + 50 $(N)^2$]

Where: N is the percentage, by weight, of nitrogen in the oil. Note: For residual oils having high (>0.5%, by weight) nitrogen contents, one should use 120 lb NO_2/10^3 gal (15 kg NO_2/10^3 liter) as an emission factor.

Chapter 9

Coal Burning

The problem of energy supply has refocused attention upon coal as a viable energy resource, and the changeover of coal-burning facilities to either oil or natural gas has halted. This changeover, which became popular in the 1960s, was stimulated by both economic and air quality considerations.

In the late 1960s natural gas was available at an average cost of \$0.64 per 10^6 Btu, low-sulfur oils at \$0.72 per 10^6 Btu, and coal at around \$0.50 per 10^6 Btu. Due to the considerably greater capital investment required to burn coal acceptably, there was little incentive for burning coal. Although today the physically and environmentally cleaner fuels have much to recommend them, federal energy policy as well as major energy users are vitally concerned with fuel availability, which has become a most important feature of the economics involved.

This chapter introduces the fundamental practical aspects of coal combustion. Additional details may be found in the references.

Coal, as found in nature, occurs in seams of varying thickness and at various depths in the earth. As mined, coal will contain varying amounts of fixed carbon, volatile matter, sulfur, clay, and slate. It is classed into four broad ranks in accordance with ASTM D-388 (1) (see Attachment 3-10), which essentially categorizes it by considering fixed carbon and calorific values. An obvious air pollution concern relates to its sulfur content, which ranges from 0.5 percent or less, to something over 8 percent, depending on source. Table 9-1 lists estimates of coal reserves by rank in terms of sulfur content. Bituminous coals are the more commonly used steaming coals, though sub-bituminous coal is increasing. The distribution of major bituminous coal sources is shown in Table 9-2 (see Attachment 3-9 for a more complete total). Ash content is an important parameter, both in terms of firing equipment and particulate emissions. Sulfur and ash content are somewhat interrelated, in that some of the coal "ash" is due to the presence of iron pyrites, which also contain sulfur.

Table 9-1. Estimated coal reserves—billions of tons.

Coal rank	**Sulfur content**			
	<0.7	**0.8-1.0**	**1.1-1.5**	**>1.5**
Bituminous	104	111	49	464
Sub-bituminous	256	130		1.3
Lignite	344	61	41	0.5
Anthracite	14	96		
TOTALS	720	303	90	466
Percent of 1500	46	19	6	29

Table 9-2. Bituminous coal source distribution.
Billions of tons, estimated (4). Location of some major deposits.

State	Sulfur content %			
	<0.7	0.8-1.0	1.1-1.5	>1.5
Alaska	20			
Colorado	25	37		
Illinois			4.9	138
Kentucky	18.6	6.5	3.3	40
Missouri				78.7
Ohio				41
Pennsylvania			7.6	49
West Virginia	20.7	26.7	21.8	33
Wyoming	6.2	6.6		

Source: U.S. Bureau of Mines Circular 8312

The sulfur in coal is found in both organic and inorganic forms, with somewhat over fifty percent as in organic iron pyrite and marcasite (2). Coal cleaning at the mine will reduce the ash content and simultaneously reduce the sulfur content by removing some of the iron pyrites. Cleaning is accomplished by gravimetric separation, which is a successful method because pyrites are about five times more dense than coal. Unfortunately, methods to reduce organic sulfur are not economic at this time. Consequently, flue-gas-desulfurization may be required. Although the costs are very high, successful schemes have recently been demonstrated (5). The urgent need for sulfur emission control and the limited availability of low-sulfur fuels will continue to stimulate economic and legal incentive to speed the development of improved control systems.

To choose coal as a fuel for a given plant site, its storage must be considered. Fresh coal slowly deteriorates when exposed to weathering. Careful attention must be given to the manner in which the coal is stockpiled; large piles loosely formed can ignite spontaneously. This problem is most severe with smaller sizes and high sulfur content. Where very large storage is needed, such as at power stations, stock piles are created by using large equipment to form piles several hundred feet wide, several thousand feet long, and about twenty feet high. Coal is distributed in layers and compacted with "sheep's foot" rollers to minimize air pockets. Where smaller quantities are stored and turnover is rapid, conical piles are used with a 12-foot depth or less. Where open piles are not permitted, silos are used for coal storage. These are equipped with fugitive dust control for use during loading.

Coal is burned in a wide variety of devices, depending on the rate of energy release desired, the type and properties of the coal burned, and the form in which it is fired. In general, firing can be accomplished by using either overfeed or underfeed stokers, with residence burning on grates, or by using pulverized feed where coal burns in suspension essentially as a fluidized-solid. Spreader stoker-fired units tend to combine an overfeed scheme with suspension burning. Cyclone furnaces operate with the coal converted to molten slag.

What characteristics of coal influence the choice of firing equipment and operational procedures? Combustion requires oxygen, commonly provided by admitting atmospheric air. The chemical analysis of the fuel determines the amount of air needed. The combustibles in coal are carbon, hydrogen, and sulfur. The minimum theoretical (stoichiometric) air supply is that which will fully oxidize these combustibles. To compute this quantity requires the knowledge of the quantities of each element present in a coal, information which is provided by the ultimate analysis. To determine such an analysis requires a well-trained chemist in a well-equipped laboratory.

A second analysis containing less chemical data, but still quite useful nevertheless, is the proximate analysis. This analysis gives the fixed carbon, volatile matter, ash, and "free moisture" found in a given coal. While it cannot provide specific chemical data, it does provide relative burning data. For example, fixed carbon is that carbon in coal which is a solid, as opposed to that which may be combined in volatile matter and can be "boiled off" as a gas when coal is heated. For a given size of coal, the required burning time is increased as the fixed carbon increases. While this may seem of importance only for grate-fired units, it is also important in pulverized firing. A coal with higher fixed carbon probably would have to be pulverized to a higher percentage fines compared to one of lesser fixed carbon content. Because of fuel variability, some plants routinely sample each railcar of coal for analysis.

A typical "as-received" proximate analysis is given in Table 9-3.

Table 9-3. Proximate analysis—as received (6)

	Percent by weight
Fixed carbon	75.26
Volatile matter	17.91
Moisture	3.10
Ash	3.73
	100.00

The moisture of the proximate analysis is the "free moisture," and will vary according to how the coal is handled. An ultimate analysis of the same fuel is given in Table 9-4.

Table 9-4. Ultimate analysis—as received (6).

	Percent by weight
Carbon	84.02
Hydrogen	4.50
Oxygen	6.03
Sulfur	0.55
Nitrogen	1.17
Ash	3.73
	100.00

As mentioned earlier, the data provided by the ultimate analysis are useful in computing theoretical air requirements. For example, the theoretical air computation for the coal in Table 9-4 is:

$$\textbf{(9.1)} \qquad \textit{theoretical air} = 11.53\ C + 34.34\ (H_2 - \frac{O_2}{8}) + 4.29S$$

$$= 11.53\ (.8402) + 34.34\ (.0450 - \frac{.0603}{8})$$

$$+ 4.29\ (0.0055)$$

$$= 11.00 \text{ lbs. per lb. of coal}$$

The excess air required for this coal would vary depending, upon the method of firing, but may range from a low of 10 percent, for pulverized firing, to 60 percent for small stoker-fired units. The mass of gas flow required in a given system can be determined for the fuel, which in turn establishes the gas volume at a specified temperature and pressure. Operation with a fuel that varies from the design analysis may be accommodated by proper controls and training of operating personnel. As an example, spreader stokers with a traveling grate are normally operated with an ash depth of two to four inches. An increase of coal ash content requires increased running speed for the grate to maintain the same ash thickness. This is consistent with the need to feed more coal to achieve a desired energy release rate. Air-flow adjustment must also be in proper proportion to insure good burning.

There are other characteristics of coal which influence the design and operation of firing equipment. Among these are: ash fusion temperature, free-swelling index, and grindability. Grindability reflects the relative ease with which coal can be ground. The free-swelling index and ash fusion temperature are important indicators of the behavior of the ash under different conditions. For burning on grates, the free-swelling index is important, since it is a measure of ash's tendency to agglomerate or cake. For systems where the grates have no motion to break up the crust, a free-swelling index of five or less is needed. Ash fusion temperature must be high enough to prevent molten ash from forming clinkers in the case of grate units, or from adhering to heat exchange surfaces in pulverizing units. Cyclone furnace or wet-bottom furnaces require ash fusion temperatures high enough to insure good operation.

Methods of Firing

A large variety of mechanical stokers has been developed for burning coal. The operating principles vary in terms of how the coal is introduced into the furnace. Feeding can take place from below, from above, or by broadcasting onto a grate. Each of these feeding methods has considerable influence upon the design of the furnace, boiler, and associated subsystems.

Stokers tend to fall into one of the categories given in Table 9-5; their steam-generating capacities fall in the following ranges:

Underfeed—30,000 lbs/hr or less
Spreader—75,000 lbs/hr to 400,000 lbs/hr
Vibrating—50,000 lbs/hr to 200,000 lbs/hr

Table 9-5. Stoker types and energy rate.

Type	Energy rate Btu/ft^2 hr.
Underfeed—single retort	400,000 max
Underfeed—multiple retort	600,000 max
Chain and traveling grate	300,000—500,000
Spreader—dump grate	250,000
—Traveling with continuous ash discharge	750,000 max
Vibrating grate	400,000 max

Spreader stokers are more commonly found in existing units than are vibrating grate systems. Pulverized-fired units are becoming more common for 100,000 lb/hr or greater capacity. This trend is due to the cost of stoker coal, compared to coal suitable for pulverizers. Stoker coal is usually low ash, preferably less than 10 percent with volatile matter from 5 to 20 percent and a size consist range between ¼" and 1.5". Coal for pulverized firing can be run-of-mine with ash content to 30 percent. Prior to the fall of 1973 the price per 10^6 Btu for stoker coal was considerably greater than run-of-mine coal. Prices for both types of coal are variable, and it is not possible to state a cost differential at this time. Also note that demand for low sulfur coal exceeds supply to the extent that usual quality control at the mine has deteriorated.

For a given energy input, Table 9-5 may be used to establish the grate area required. This is illustrated by assuming a spreader stoker fired unit with a traveling grate which must produce 10^8 Btu/hr from burning coal with a HHV of

26×10^6 Btu/ton. The HHV of 26×10^6 Btu/ton is equivalent to 13,000 Btu/lb, which is a good quality coal that could be fired at the maximum rate of 750,000 Btu/hr ft^2 in Table 9-5. Therefore, the area needed is:

$$\frac{10^8 Btu/hr}{.75 \times 10^6\ Btu/ft^2\ hr} = 1.33 \times 10^2 \text{ ft}^2, \text{ and the feed rate}$$

is:

$$\frac{10^8}{.26 \times 10^8} = 3.85\ Ton/hr$$

The net grate area establishes the furnace cross section, since the grate is usually designed with a length approximately 1.2 × width. The energy release per unit volume for burning coal is about 30,000 Btu/hr ft^3. Utilizing data from the example, the furnace volume would be given by:

$$\frac{10^8 Btu/hr}{30{,}000\ Btu/hr\ ft^3} = 3.33 \times 10^3 = 3330\ ft^3$$

This dimension, coupled with area previously calculated, would result in a furnace about 25 feet high.

Table 9-6 summarizes the volumetric energy release rates normally employed in coal-burning systems.

Table 9-6. Heat release rates—design values.

	Btu/hr per cu. ft.
Pulverized coal	20,000 to 30,000
Stokers—continuous ash removal	30,000 to 35,000
Stokers—dump or stationary	15,000 to 25,000

Mechanical stokers universally require coals with ash fusion temperature high enough to prevent molten ash formation on grates. Cyclone coal furnaces, shown in Attachment 9-1, on the other hand, are designed to operate with the ash in molten slag condition. These units are usually fired with coal that has been ground fine enough to pass through a "No. 4" screen. Coal is fed into one end of a cylindrical furnace and air is admitted tangentially. Gases therefore rotate as they flow down through the water-cooled furnace structure. The ash reaches fluidity temperature and flows through the furnace as a molten slag. Slag temperatures range from 2,500 to 3,000°F. Energy release rates for these furnaces range between 450,000 to 800,000 Btu/ft^3. Large steam generators may employ two or more of these furnaces. A significant characteristic of this firing method is very low fly ash entrainment, a definite advantage for particulat emission control. Cyclone furnaces are no longer being built due to high NO_X emissions.

Air Supply and Distribution

The determination of combustion air has been previously presented; but questions remain about how and where the air should be introduced. Resolution of these questions depends upon the type of firing and rank of coal. Lower design values, as specified for heat release rates given in Table 9-6 apply to lower rank coals. Where the air is to be introduced is influenced by the method of firing and the amount of volatile matter. Underfeed retort stokers usually require very little overfire air, regardless of the type of fuel fired. This can be explained by examining Attachments 9-2 and 9-3. The coal retort is normally the region in which "green" coal undergoes distillation as it moves up through the fuel bed. Volatile gases flow upward through a burning carbon region and as they flow, air from the tuyeres provides good mixing, and therefore good burning. Since gaseous hydrocarbons which may leave the fuel bed are well mixed with air, additional air is not required either for turbulence or to maintain proper oxidation.

Mechanical stokers which employ overfeed or spreader feed represent a different problem, both with respect to excess air and air distribution. Underfeed stokers would employ 50 to 60 percent excess air with all entering as underfire air. Overfeed units, such as the chain-grate stoker shown in Attachment 9-4, require some overfire air in addition to a controlled air flow along the grate itself. The chain grate unit operates with coal fed from the gate which maintains a 5" to 7" fuel bed thickness, with ignition occuring downstream of the gate. Ignition progresses from the top surface down as the coal moves from left to right. Gases which evolve as the coal is heated leave this fuel bed near the feed end. Therefore, air must be added from above to provide the needed oxygen and turbulence for oxidation of the combustible gases. Depending upon the coal's volatility, overfire air can be as much as 20 percent of the total air supplied. Excess air ranges from 25 to 50 percent, depending upon coal rank and upon size consist. Overfire air is normally supplied from a booster fan system as seen in Attachments 9-6 and 9-7, rather than from a forced-draft system.

Underfire air must be regulated to provide greatest flow where coal ignites and along the region where fixed carbon burns in residence. Since grate sections are all alike, underfire air flow is regulated by controls in each compartment.

The vibrating grate stoker, Attachment 9-6, represents another variation. Here the ash end of the grate is below a low arch which causes air flow through the bed to move back into the main furnace region. The low arch tends to radiate energy back to the fuel bed, thus helping to keep temperature up and ensure good burnout. Arches of this type would be used with low volatile matter coals and will be found in chain or traveling grate units where such coals are burned (see Appendix 9-1).

The spreader stoker-traveling grate unit illustrated in Attachment 9-7 represents still another variation. In these units the spreader distributes coal by broadcasting it from front to back. Large pieces go to the rear, fines burn in suspension. Here overfire air must be provided at the back and from the sides as well. Air jets are sometimes placed near the spreaders to prevent fines from piling locally. Suspension burning also results in carbon carryover, part of which normally settles out in one or more gas pass regions of the boiler. This particulate is reinjected with the overfire air, again using a separate forced draft fan to supply the needed air at high enough pressure to operate the reinjection arrangement. Spreader stokers were quite popular in the past since they were able to handle a wide variety of coals and were suitable for steam generators with capacities to 400,000 lbs. of steam per hour. They do require a consist ranging from ¼" to 1¼" equivalent round hole with no more than 10 percent passing a ¼ mesh screen. Consist of ¼" to ¾" is even better, but coal costs are higher when closer size consist control is specified. Cost and availability of good stoker coals has caused a shift to pulverized coal firing in recent years for units as small as 100,000 lbs. per hour steam capacity. Pulverized coal burning can be accomplished using run-of-the-mine consist coal, with ash content to 20 or even 30 percent. Mechanical stokers usually do not operate properly with high ash content coal. One other area of difficulty with spreader stokers occurs when the unit is operating at light loads (less than 25 percent). When loads are small, it becomes difficult to maintain a proper fuel bed on the grates.

Air distribution in pulverized fired coal burners (see Attachment 9-8) is divided between primary and secondary air. Primary air is used to transport coal from the pulverizers to the burners. About 2 lbs. of air per lb. of coal is required. Transport velocities are typically 4000 to 5000 fpm with 3000 fpm a minimum. Secondary air is usually introduced at the burners, but can be introduced at other locations in the furnace.

Cyclone furnaces introduce approximately 20 percent of the required combustion air with the coal feed to the burner. Secondary air is admitted tangentially into the main barrel of the furnace. A small amount of air, up to 5 percent, can be admitted at the center of the radial burner.

In general, coal-fired steam generators will smoke when air quantity is inadequate, or when the air is improperly distributed, or when too much excess air is used. Improper distribution can be caused by faulty control, or by improper fuel bed conditions where burning occurs on grates with poor air distribution through the fuel bed. This condition can be caused by a too-deep or non-uniform fuel bed, or by low ash-fusion temperature. Ash fusion gives rise to air flow pattern distortion, since it causes clinkers or crusts to form through which air cannot flow. Normally this problem can be spotted visually by the boiler operator, and the clinkers can then be removed. A good coal fire has a bright yellow-orange flame with slightly hazy tips. A whitish or "cold"-looking fire probably has too much air. Proper combustion control requires either a CO_2 *or* O_2 flue gas monitor. The O_2 meter is preferable where several fuels can be fired. Generally, CO_2 should range from 10 to 13 percent in flue gas from stoker-fired units and from 13 to 15 percent for pulverized units. O_2 content ranges from 2 to 8 percent, depending on the type of firing.

Air Pollution Considerations

Coal combustion is responsible for a significant fraction of the annual SO_x and particulate inventory. SO_x control can be accomplished by either prevention or abatement. Prevention requires either *a priori* removal of sulfur from coal or limiting coals fired to those with very low sulfur content. Very probably, both approaches will be needed if the nation's energy needs are to be adequately met, at least in the next decade or so.

A short-term solution which seems to be available is the use of low-sulfur western coal as a replacement for high-sulfur eastern coal. Such coal can theoretically be transported by pipeline or rail or both. Unfortunately, as is so often true of a particular technology, boilers designed for eastern coal do not thrive on a diet of western coal. The difficulty arises from the fuel properties: high inherent moisture content, lower calorific value, and fouling characteristics.

Sub-bituminous coal found in parts of Wyoming and Montana contain 20 to 30 percent moisture which is inherent in the coal. This moisture is part of the coal's fixed carbon content. The resulting lower heating value is further aggravated by the energy needed to vaporize the moisture. The combined effect of these two variables is a reduced flame temperature, which means reduced radiant energy transfer to the furnace walls.

In addition, the vapor present has a higher specific heat than other constituent gases which raises the flue gas specific heat. This is shown by the basic thermodynamic relationship:

$$C_{pm} = \frac{\sum_{i=1}^{r} N_i C_{pi}}{\sum_{i=1}^{r} N_i} = \sum_{i=1}^{r} y_i C_{pi}$$

where C_{pm} is the molal specific heat of a mixture of r gases, and y_i and C_{pi} are the mole fractions and specific heats of the i-th component, respectively. This increase in specific heat, coupled with lower heat utilization in the furnace (see Chapter 4) causes high heat transfer, with high temperatures in the convective superheaters, because the attemperator control range is exceeded. Reduced-capacity operation is therefore often necessary.

The reduced energy content means more coal must be used for a given output, thus increasing storage, handling, and grinding requirements. If calorific content is low, the sulfur dioxide emission standard (per mission Btu) may be exceeded, despite the supposedly low sulfur content. Ash content may also be a significant burden, due to increased total quantity of coal which must be fired. In general, the use of western coal is not a simple proposition. Uncontrolled emission factors, while not necessarily applicable to any one system, serve as a gauge for the relative impact of a number of sources.

Uncontrolled equipment emission factors are given in Table 1-1.2, page 5-30, Appendix 5-1. These factors provide estimates of the pollutant load entering the control device, based on the fuel's firing rate. These data illustrate that uncontrolled particulate emissions are near the same for large coal-fired units (100×10^6 Btu/hr) with the exception of the cyclone furnace. The lower particulates emitted from a cyclone furnace illustrate the advantage of feeding a course grind and operating with molten ash. There is a penalty, however, in the form of an increased NO_X emission, because the operation takes place at significantly elevated temperatures. This same situation can be seen in slag-top (wet-bottom) pulverized coal units.

Chapters 16 and 17 will present NO_X-control theory and experience. An economic "state of the art" has not yet evolved. However, two techniques currently receiving major attention are: excess air control and staged firing. Flue gas recirculation, which is effective in controlling NO_X from gas combustion, is much less effective with coal combustion. It is difficult to predict which of several techniques will emerge as more practical and useful. The amount of NO_X control which is required and economics will both play a large part in this picture. Expensive oil may very well serve to accelerate the development of better coal pollution control methods.

At the present time, electrostatic precipitators and wet scrubbers appear to be the acceptable methods to control particulate and SO_X emissions from relatively large sources. Concern about the emissions of fine particulates may result in increased use of baghouses.

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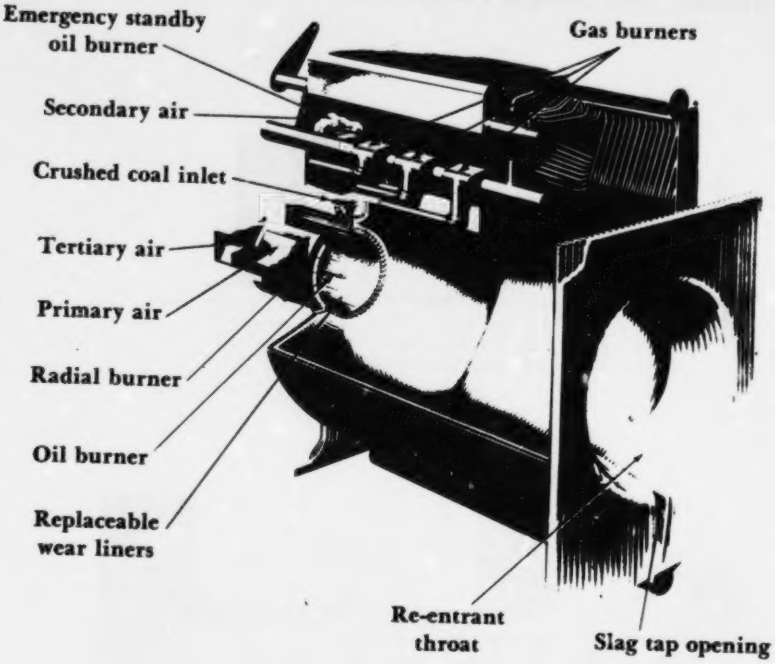
Attachment 9-1. Cyclone furnace[2]


Emergency standby oil burner
Gas burners
Secondary air
Crushed coal inlet
Tertiary air
Primary air
Radial burner
Oil burner
Replaceable wear liners
Re-entrant throat
Slag tap opening

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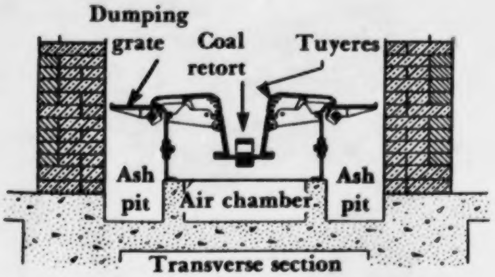
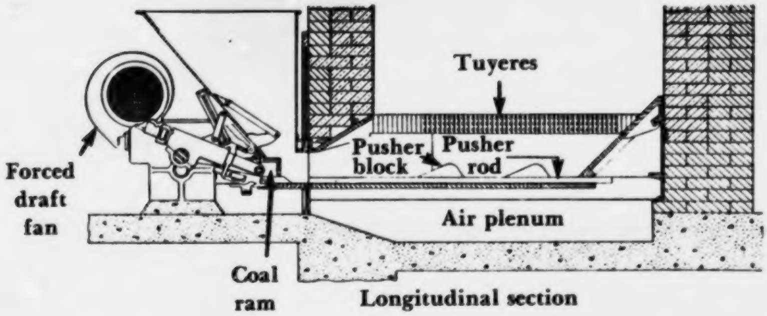
Attachment 9-2. Single retort underfeed stoker[3]


Dumping grate
Coal retort
Tuyeres
Ash pit
Air chamber
Ash pit
Transverse section


Tuyeres
Pusher block
Pusher rod
Forced draft fan
Air plenum
Coal ram
Longitudinal section

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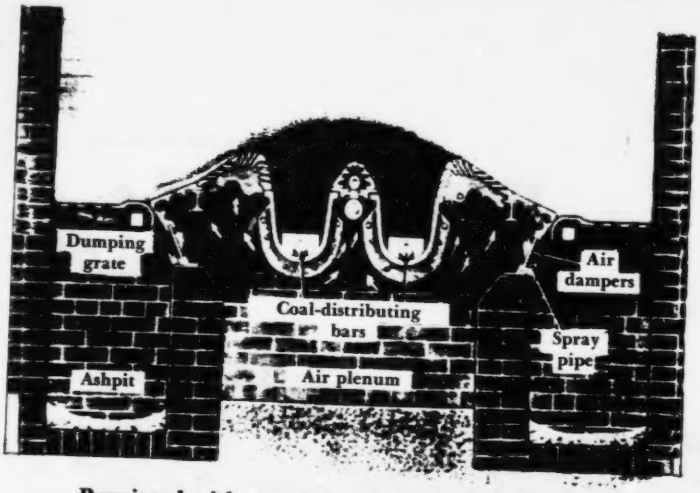
Attachment 9-3. Section thru underfeed stoker[3].


Dumping grate
Air dampers
Coal-distributing bars
Spray pipe
Ashpit
Air plenum

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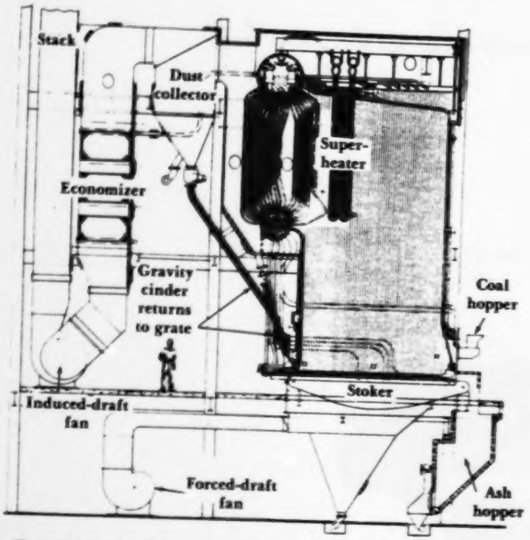
Attachment 9-4. Chain grate stoker[3].


Stack
Dust collector
Super-heater
Economizer
Gravity cinder returns to grate
Coal hopper
Stoker
Induced-draft fan
Forced-draft fan
Ash hopper

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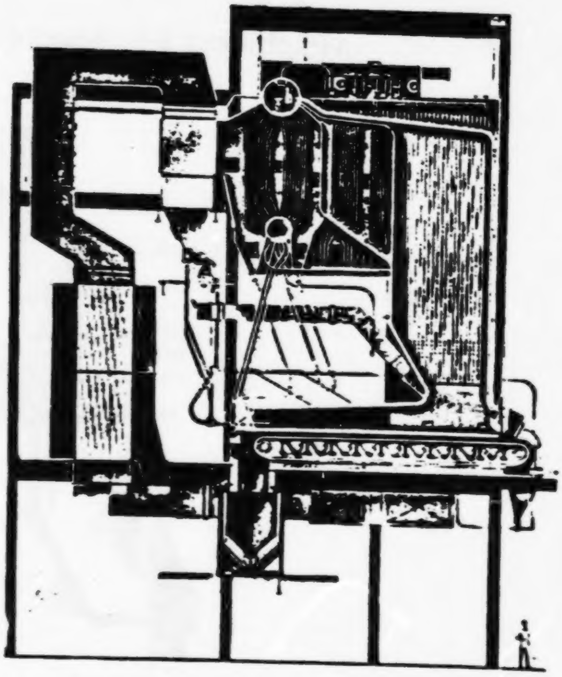
Attachment 9-5. Chain grate fired steam generator[3].



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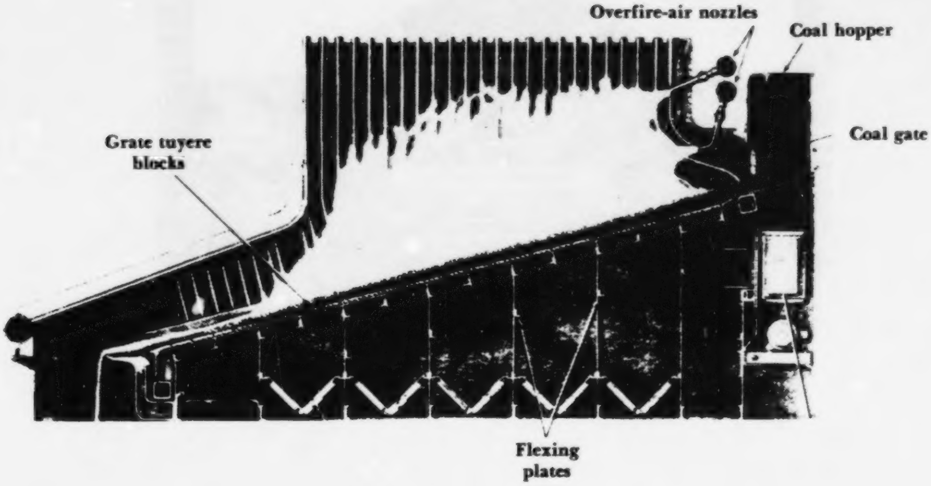
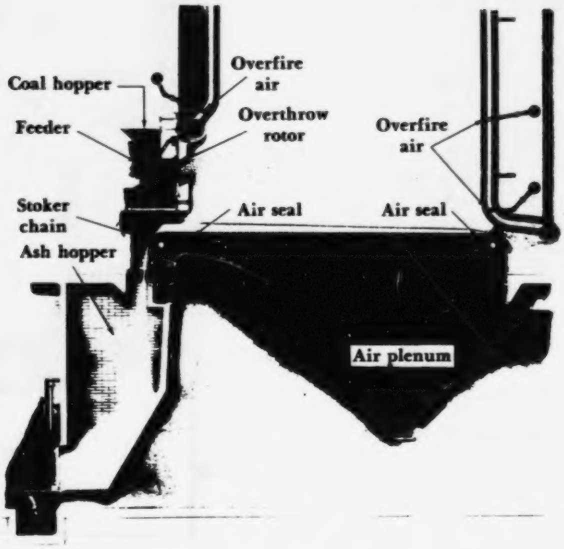
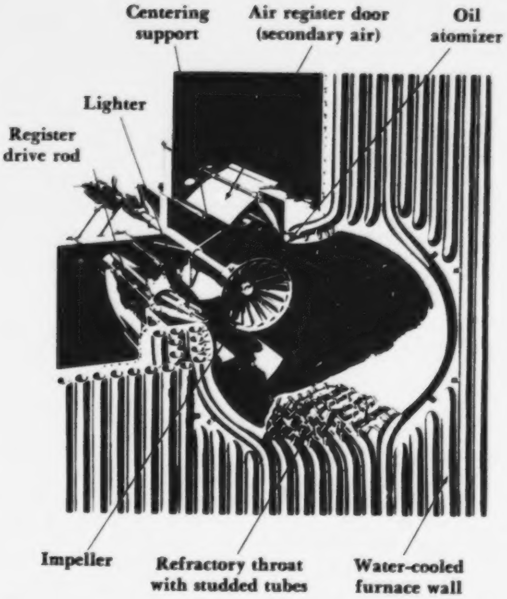
Attachment 9-6. Vibrating grate stoker[7]


Overfire-air nozzles
Coal hopper
Coal gate
Grate tuyere blocks
Flexing plates

Attachment 9-7. Spreader stoker traveling grate unit[2]


Coal hopper
Overfire air
Feeder
Overthrow rotor
Overfire air
Stoker chain
Air seal
Air seal
Ash hopper
Air plenum

Attachment 9-8. Pulverized coal burner[2]


Centering support
Air register door (secondary air)
Oil atomizer
Lighter
Register drive rod
Impeller
Refractory throat with studded tubes
Water-cooled furnace wall

CORROSION AND DEPOSITS FROM COMBUSTION GASES

William T. Reid*

A rough estimate a few years ago by the Corrosion and Deposits Committee of ASME placed the direct out-of-pocket costs of external corrosion and deposits in boiler furnaces at several million dollars a year. It is difficult to pinpoint costs directly, but certainly the unscheduled shut-down of a large steam generator through failure of a superheater element can be an expensive operation. Crossley of CEGB in England estimates that an outage of a 550-megawatt unit for one week costs $300,000. Hence extensive efforts have been made in this country and abroad to learn more about the factors that lead to metal wastage and deposits and how to control them in combustors of all kinds.

Of the fuels being used for central-station power plants, only natural gas is free from the "impurities" that cause these problems. Ash in coal and in fuel oil and the presence of sulfur lead to a wide variety of difficulties. In boilers, deposits form within the furnace, on the superheater and reheater elements, in the economizer, and in the air heater. In gas turbines, combustor problems are not so severe, but deposits on turbine blading can be disastrous.

Although deposits may be objectionable in themselves, as thermal insulators or flow obstructors, usually it is the corrosion conditions accompanying deposits that cause the greatest concern. This has been particularly true in boiler furnaces. Here, deposits interfere with heat transfer and gas movement, but these can be compensated in part by engineering design. On the other hand, corrosion beneath such deposits can cause rapid metal wastage, forcing unscheduled outages for replacement of wall tubes or superheater elements.

With the recent trend to larger and larger steam generators, even up to 1130 megawatts, the importance of eliminating such outages grows in importance. This is the reason mainly, why so much attention has been paid recently to investigating the causes of corrosion and deposits, and to seeking corrective measures.

IMPURITIES IN FUELS

Although natural gas, with its low sulfur content and complete freedom from metallic elements, is the only fuel not causing troubles with corrosion and deposits, its availability and cost limit its use for steam-electric plants to geographical areas where gas is less expensive than other fuels on a Btu basis. Thus, despite its freedom from corrosion and deposits, natural gas is the source of energy for only a fifth of the electricity generated in this country. It is important to realize, then, that although corrosion and deposits are indeed troublesome in the operation of steam-electric plants, it is only one of many factors that play an important role in selecting a fuel or designing a power plant to operate at minimum cost.

Residual fuel, which provides the energy for about 6 percent of our generated electricity, usually contains all the impurities present in the original crude oil. Of these, sodium, vanadium, and sulfur are most troublesome. Typical limits for these impurities are, for sodium, 2 to 300 ppm in residual fuel, or about 0.1 to 30 percent Na_2O in the ash; for vanadium, 0 to about 500 ppm in residual fuel, or 0 to 40 percent V_2O_5 in the ash; and for sulfur, up to 4 percent in residual fuel, with a maximum of 40 percent SO_3 appearing in oil ash depending upon the method of ashing.

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*Senior Fellow, Battelle Memorial Institute, Columbus, Ohio. Presented at the Residential Course on Combustion Technology, Pennsylvania State University, 1966.

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With coal, which furnishes more than half of the energy converted into electricity, the impurities consist mainly of SiO_2, Al_2O_3, Fe_2O_3, CaO, MgO, the alkalies, and, of course, sulfur. The range of these ash constituents varies widely, and they may exist in many mineralogical forms in the original coal. Sulfur may be present even up to 6 percent in some commercial coals, but the sulfur content usually is below 4 percent. Sulfur retained in coal ash as SO_3 ranges up to about 35 percent, depending upon the method of ashing and the amount of CaO and MgO in the ash. In coal-ash slags it is seldom more than 0.1 percent. Chlorine is frequently blamed for corrosion with English coals in which it occurs up to 1 percent; it seldom exceeds 0.3 percent in American coals, and it usually is less than 0.1 percent. Because less than 0.3 percent chlorine in coal does not cause problems through corrosion and deposits, chlorine in American coals generally may be neglected as a source of trouble. Phosphorus, which occurs up to about 1 percent as P_2O_5 in coal ash, was a frequent source of deposits when coal was burned on grates. With pulverized-coal firing, however, it is seldom held responsible for fouling.

PROPERTIES OF COAL AND OIL ASHES

Coal Ash

Most of the earlier studies of coal ash were aimed at clinkering problems in fuel beds. Later, studies of ash were concerned with the unique problems involved with slag-tap pulverized-coal-fired boiler furnaces. Ash deposits, collecting on heat-receiving surfaces, cause no end of trouble because they interfere with heat transfer. In the combustion chamber, particularly in pulverized-coal-fired slag-tap furnaces, the layers of slag are fluid and can cover much of the heat-receiving surface.

In dry-bottom furnaces, wall deposits are made up largely of sticky particles that coalesce to cover the tubes in irregular patterns. As the gases cool on passing through superheaters and reheaters in either type of furnace, adherent ash deposits sometimes become so extensive as to block gas flow. In air heaters, ash accumulations again can be troublesome.

The flow properties of coal-ash slags were investigated extensively in this country nearly three decades ago when slag-tap furnaces were still quite new. More recently, those early data have been rechecked and affirmed in England. Although coal ash makes up a 6-component system, it has been found possible to combine compositional variables so as to provide a relatively simple relationship between viscosity, temperature, and composition. It has been found, for example, that slag viscosity above the liquidus temperature can be related uniquely to the "silica percentage" of the slag, where

$$\text{Silica percentage} = \frac{SiO_2}{SiO_2 + Fe_2O_3 + CaO + MgO} \times 100.$$

Here SiO_2, Fe_2O_3, CaO, and MgO represent the percentage of these materials in the melt. This relationship was found to hold for widely varying ratios of Fe_2O_3 to CaO + MgO and to be almost completely independent of the Al_2O_3 content. The relationship, admittedly an empirical one, can be simplified still further to the form

$$\log (\eta - 1) = 0.066 (SiO_2 \text{ percentage}) - 1.4$$

where η is the viscosity in poises at 2600 F. A much more elaborate treatment of this relationship was one of the useful results of the recent work in England.

The rate of change of viscosity with temperature also is relatively simple, of the form

$$\eta^{-0.1614} = (4.52 \times 10^{-4} t) - B$$

where η is the viscosity in poises at temperature t in degrees F, and B is a constant fixed for each slag. The viscosity at 2600 F can be inserted in this equation to determine B, after which the viscosity of the slag can be calculated for other temperatures. Again, the British have worked out a more elaborate but equally empirical relationship.

At some point when coal-ash are cooled, a solid phase separates which radically affects viscosity by changing the flow from Newtonian to pseudoplastic. Related to the liquidus temperature, this is known as the "temperature of critical viscosity" (T_{cv}) for coal-ash slags. At this point, important changes occur in flow behavior, and the slag may no longer deform under gravitational forces. This, in turn, greatly affects the thickness of slag that can accumulate on the furnace walls, the thickness being greater as T_{cv} is higher and as the Newtonian viscosity is greater, all other factors being constant.

The temperature at which this pseudoplastic behavior begins is related to composition in a most complicated fashion. No such simple relationship as the silica percentage has been found to apply to T_{cv}, which is also affected by such factors as the rate of cooling of fluid slag. For the present, it is enough to know that this is an important factor in fixing the thickness of slag on heat-receiving surfaces, particularly where the temperature of the slag is well below 2600 F. The relationships here between slag accumulation, coal-ash properties, and furnace conditions are extraordinarily complex, at least a dozen parameters being involved. Little use has been made of this analysis, largely because T_{cv} is not related simply to composition and may have to be determined experimentally for each slag composition.

Oil Ash

Possibly because the ash content of residual fuels seldom is greater than 0.1 percent, exceedingly low compared with coal, the properties of oil ash have not been investigated systematically. Silicate minerals in crude oil vary much more widely than in coal ash, and Al_2O_3 and Fe_2O_3 also cover broad limits. Alkalies may be high in residual fuel, often because of contamination in refining the crude oil, or in handling. Seawater, unavoidably present in bunkering, is a common contaminant in residual fuel. Sulfur occurs in oil in a wide variety of forms ranging from elemental sulfur to such complexes as thiophene and its homologues.

The uniqueness of most oil ashes is that they contain, in addition to extraneous materials, metallic complexes of iron, nickel, and vanadium present as oil-soluble organometallic compounds. These are frequently porphyrin-type complexes, so stable that temperatures in excess of 800 F usually are necessary to dissociate them. As a result, they are difficult to remove from fuel oil economically. An undescribed scheme for removing essentially all the nickel and vanadium from residual fuel at a cost as low as 15¢ a barrel was mentioned at the Marchwood Conference in 1963, but the scheme has not been applied commercially as yet. Usually, water-washing and centrifuging are the only procedures economically possible for upgrading low-cost residual fuel.

During combustion, all these complexes are destroyed, probably liberating the metals as oxides. With vanadium, for example, there seems to be a progressive oxidation from V_2O_3 to V_2O_4, and eventually with enough excess air to V_2O_5. The melting point and vapor pressure of these oxides vary widely, with the reduced forms having a higher melting point than the oxidized material. At the high temperatures in flames, there is a further tendency to produce a whole series of vanadates, of which sodium vanadyl vanadate, $Na_2O \cdot V_2O_4 \cdot 5V_2O_5$, is typical. Melting points vary widely too, being only 1157 F for this compound.

Hence it is a liquid at the temperature of superheater elements, thereby adding to its aggressiveness in causing corrosion.

The fusion characteristics of oil ash are poorly known. Cone fusion and other arbitrary schemes such as hot-stage microscopes have been used to check on the melting characteristics of oil ashes, but no systematic investigation has been made as with coal ash.

EXTERNAL CORROSION

Tube wastage first posed serious problems in boiler maintenance beginning about 1942, when a sudden rash of wall-tube failures in slag-tap furnaces was traced to external loss of metal. In the worst cases, tubes failed within three months of installation. Measurements of tube wall temperature showed that the tube metal was not overheated, typical maximum wall temperature being 700 F. Heat transfer also was nominal. The only unusual condition was that some flame impingement appeared likely in the affected areas.

It was soon found that an "enamel" was present beneath the slag layer where corrosion had occurred. This material, which was found in thin flakes adhering tightly to the tube wall, resembled a fired-porcelain coating with a greenish blue to pale blue color. These flakes of enamel were moderately soluble in water, giving a solution with a pH as low as 3.0. They also contained large amounts of Na_2O, K_2O, Fe_2O_3, and SO_3, and were obviously a complex sulfate. Following considerable work in the laboratory, the "enamel" was finally identified as $K_3Fe(SO_4)_3$. There is a corresponding sodium salt, as well as a solid solution of these sodium and potassium iron trisulfates.

Alkali ferric trisulfates were formed by reaction of SO_3 with Fe_2O_3 and either K_2SO_4 or Na_2SO_4, or with mixed alkali sulfates. At 1000 F, at least 250 ppm SO_3 is necessary for the trisulfates to form. At this temperature, neither the alkali sulfates nor the Fe_2O_3 alone will react with this concentration of SO_3. Only when both the sulfates and Fe_2O_3 are present will the reaction occur. The trisulfates dissociate rapidly at higher temperatures unless the SO_3 concentration in the surroundings is increased. Quantitative data are few, but it appears that the concentration of SO_3 required to prevent dissociation of the trisulfates at 1200 F to 1300 F, as would be the case on superheater elements, greatly exceeds any observed SO_3 levels in the gas phase. Accordingly, some unique but as yet unexplained action must go on beneath superheater deposits that can provide the equivalent of, perhaps, several thousand ppm of SO_3 in the gas phase. Lacking any better explanation for the time being, "catalysis" is usually blamed.

THE IMPORTANCE OF SO_3

Any discussion of external corrosion and deposits in boilers and gas turbines would be meaningless without reference to the occurrence of SO_3 in combustion gases. Many investigators, both in the laboratory and in the field, have studied the conditions under which SO_3 is formed, on the basis that SO_3 is a major factor both in high-temperature corrosion and in low-temperature corrosion and deposits. These studies have been going on for more than 30 years.

The reasons are not difficult to state. In the hot end of coal-fired equipment - furnace-wall tubes and superheater elements, for example - deposits taken from areas where corrosion has occurred invariably contain appreciable quantities of sulfates, sometimes as much as 50 percent reported as SO_3. Slag layers from the high-temperature zone of oil-fired boilers also contain SO_3, typically from 25 to 45 percent reported as Na_2SO_4. In the 1959 Battelle report to ASME, many examples are given of slag deposits where there was more than 15 percent SO_3 in the deposit.

As has already been noted, the alkali iron trisulfates cannot exist at 1000 F unless at least 250 ppm of SO_3 is present in the surrounding atmosphere, or the equivalent SO_3 level is provided some other way. At higher temperatures, even more SO_3 must be present if these compounds are to form. In the absence of SO_3, the trisulfates could not be produced and corrosion would not occur.

Bonding of ash to superheater tubes frequently attributed to a layer of alkalies that condenses on the metal wall and serves as the agent to attach the ash to the tube. Further buildup of ash deposits, however, depends on some other mechanism. One explanation with fuels such as some subbituminous coals, lignite, and brown coal containing large quantities of CaO in the ash is that $CaSO_4$ is formed. This substance, well distributed in the ash deposit, is considered by many investigators to be the matrix material that bonds the whole deposit together into a coherent mass. Although $CaSO_4$ might be formed when CaO reacts with SO_2 and O_2, it seems more reasonable to expect that SO_3 is responsible.

At low temperatures, as in air heaters, there is no question but that SO_3 is the major offender. It combines with alkalies to plug air-heater passages, and if the metal temperature is below the dewpoint, H_2SO_4 formed from SO_3 condenses as a liquid film on the metal surfaces to cause serious corrosion. Acid smuts, where carbon particles are saturated with this H_2SO_4, also depend on the presence of SO_3.

These are the reasons why the formation of SO_3 has been given so much attention. In addition to the boiler manufacturers and the fuel suppliers working in their own laboratories and in the field, Battelle has studied the production of SO_3 in flames and by catalysis for the ASME Committee on Corrosion and Deposits. This work has provided a basic understanding of many of the thermochemical reactions leading to corrosion and deposits.

LOW EXCESS AIR

A revolutionary approach has been taken over the past decade in Europe toward eliminating the formation of SO_3 in boiler furnaces fired with oil by limiting the excess air to an absolute minimum. Low excess air seems to have been proposed first in England as a means of decreasing corrosion and deposits when burning residual fuel. In 1960, Glaubitz in Germany reported highly favorable results burning residual fuel with as little as 0.2 percent excess oxygen. By carefully metering fuel oil to each burner and properly adjusting air shutters, he found it possible to reduce excess oxygen to as little as 0.1 percent before incomplete combustion became troublesome. By operating at these low levels of excess air, Glaubitz was able to operate boilers on residual fuel for more than 30,000 hours without any corrosion and with no cleaning being required.

Low excess air in oil-fired equipment also has proven satisfactory in the United States and is being used successfully in many large boiler plants. Precise metering of fuel and air to each burner has proven to be less troublesome than had been expected earlier, and in some instances with high furnace turbulence ordinary controls have been found satisfactory. In other cases, unburned combustibles have made low excess air undesirable. Sound principles guide the use of low excess air, but applying these principles usefully is still largely a matter of judgment by boiler operators. It has been shown repeatedly, however, that SO_3 largely is eliminated, irrespective of the amount of sulfur in the fuel, when the products of combustion contain no more than about 0.2 percent oxygen. At this level, the dewpoint of the flue gas can be as low as 130 F where the dewpoint for the moisture in the flue gas is 105 F.

The important factors whereby low excess air is beneficial include, in addition to a decrease in SO_3, a limitation on the oxidation of vanadium. Low excess air leads to the formation of V_2O_3 and V_2O_4, which have melting points much higher than V_2O_5. Therefore, these reduced forms of vanadium are considered less objectionable from the standpoint of corrosion.

Work done recently in the laboratory shows that the main benefits of low excess air, as would have been expected, result from lack of formation of SO_3. Flame studies have shown that stoichiometric sulfur-bearing flames do not show the usual conversion of part of the sulfur oxides to SO_3 by reaction with oxygen atoms. Competing reactions within the flame simply keep the oxygen-atom level too low. Also, not enough oxygen is present to convert an appreciable amount of SO_2 to SO_3 catalytically on surfaces. The result is an SO_3 level of only a few ppm with a correspondingly low dewpoint, minimizing troubles throughout the boiler, from the superheater through the air heater.

Opinion at present is that corrosion and deposits when burning residual fuel can be essentially eliminated by operating with low excess air. Such procedures presumably will not be possible with coal unless radical changes are made in the combustion system. In the meantime, studies of corrosion and deposits continue in the search for still better ways of eliminating these causes of increased operating expense. Factors involving the formation of SO_3 are now understood fairly well. The next major step will be to develop an equally good knowledge of the mechanism whereby the trisulfates form, the other complex metal sulfates that also can be produced, and the role of vanadium. Meticulous, well-planned research in the laboratory and in the power plant will answer those questions as effectively as it has brought us to our present level of knowledge on the causes of corrosion and deposits.

Chapter 10

Solid Waste and Wood Burning

Municipal incineration has been considered a last resort in solid waste management. The major problems have been: high capital cost, high operating costs, site selection, and a long history of objectionable environmental effects. Municipal incineration's limited acceptance has stunted its technological development in this country. However, the growing shortage of suitable, available sites for landfill adjacent to large population centers has left some municipalities with no alternative.

In the last two decades, European incineration methods have experienced steady development. The U.S. has imported European technology to help meet our own needs for improved hardware. Increased fuel prices, resulting from the petroleum crisis of 1973, have focused new attention upon energy recovery from solid waste. One obvious result is the increasing consideration of solid waste for boiler fuel. Major cities such as Montreal (1), Chicago (1, 2), and Harrisburg (3) are operating modern steam-raising incinerators. The Union Electric Company in East St. Louis (4, 5) has been burning solid waste simultaneously with pulverized coal in a power boiler. Their arrangement burns shredded waste in amounts of up to 10 percent of the total fuel fired.

Systems which utilize pyrolysis, rather than oxidation, are under development but are not yet available in large-scale units. Fluidized-bed combustion is also under development, both as a potential retro-fit for coal-burning steam generators and as a source of combustion gas for gas-turbine generator systems. These innovative methods have not yet reached "state of the art" status, and long-term operating costs are unknown. For this reason, discussion here will be limited to incinerator types currently being operated or constructed.

Solid waste can be considered a fuel with an average ultimate analysis, as shown in Table 10.1 (see Attachment 3-17).

Table 10.1
Average ultimate analysis of municipal waste—as received.

	%, by weight
Carbon	28.0
Hydrogen	3.5
Oxygen	22.4
Nitrogen	0.33
Sulfur	0.16
Glass, metal, and ash	24.9
Moisture	20.7

Individual loads or daily averages at a given site may differ slightly from values given in Table 10.1. The waste produced is a function of population density and affluence. Communities tend to produce between four and seven pounds of solid waste per person per day, with 4.0 to 4.5 lb/person/day being a good rule of thumb. An incinerator design for a particular municipality should not be finalized without careful determination of both waste quantity and its ultimate analysis.

Firing Properties

The amount of air required to burn solid waste can be computed by using the data provided in an ultimate analysis. Such an analysis can be calculated from the "as received" analysis by computing the hydrogen and oxygen as shown in Table 10.1. For this example, the computation is:

$$\textit{Hydrogen in moisture} = 0.207 \times \frac{2}{18} = 0.023 \text{ lb } H/lb \textit{ waste}$$

$$\textit{Oxygen in moisture} = 0.207 - 0.023 = 0.184 \text{ lb } O/lb \textit{ waste}$$

Total hydrogen is then $3.5 + 2.3 = 5.8\%$, and the total oxygen is $22.4 + 18.4 = 40.8\%$. The air required for combustion "as received" is computed by using Equation 9.1.

$$A_t = 11.53\,C + 34.34\left(H_2 - \frac{O_2}{8}\right) + 4.29\ S$$
$$= 11.53\,(.28) + 34.34\left(.058 - \frac{.408}{8}\right) + 0 = 3.47\ \frac{lb\ air}{lb\ waste}$$

The stoichiometric air is significantly less for a pound of waste than would be for a pound of coal. Municipal solid waste contains approximately 35 percent as much energy per ton as coal, and requires approximately 35 percent as much air if fired "as received." Therefore, if one computes the air requirement on an energy-content basis, the air requirements are similar. Since it is possible to remove glass and metal from the waste by shredding and air-separation techniques (7,8), the energy content per pound of waste fired can be improved considerably.

Site Considerations

A primary problem in any waste management program is site selection. This involves public acceptance and careful systems engineering. The site chosen should attempt to minimize the total trucking costs, which include the removal of incinerator residue. In order to limit transportation cost, waste may be processed to remove metal and glass. This usually increases original waste of 300 lb/yd^3 density to around 700 lb/yd^3. This reduced transport truck volume should permit planning of collection and processing to minimize the number of collection trucks required. Careful systems study will insure optimal location for both the processing and incinerator plants.

Plant Design Considerations

The relatively small number of modern incinerators which have been built in this country in recent years, coupled with the evolution of new technology in Europe, has given rise to an unsettled "state of the art." Past practice dictated the need for primary and secondary combustion chambers. The primary chamber included a so-called "drying zone" where volatile materials were gasified and then directed into the secondary chamber to complete the oxidation. With the primary chamber operating on a large batch-fed basis, the volitization and oxidation rates varied with time, causing non-uniform furnace temperatures.

A modern incinerator may or may not have a secondary combustion chamber, depending upon whether it is designed for energy recovery. Refuse is continuously charged by mechanical stokers designed to produce uniform burning. Since solid waste does not flow when a section of piled material is torn away from the base of the pile, positive tumbling or shearing action must be provided by the stoking and feeding equipment to move waste into the furnace and onto the burning grates. A wide variety of mechanical equipment has been used but, in general, waste is charged onto a first-stage feeder from a hopper-fed vertical or near-vertical chute. The hopper is usually charged by a crane-operated grapple, but it may be fed directly by truck or front loader.

The feeder can be a ram which simply pushes waste through a gate and onto a stoker within the furnace, or it may be a short section of grate inclined at an angle of 20° to 30° placed directly beneath the charging chute. Attachment 10-1 illustrates a ram feed unit combined with a two-section reciprocating stoker.

The reciprocating stoker employs alternate rows of moving and stationary sections, shown schematically in Attachment 10-2, to move the waste through the furnace.

Attachments 10-3 and 10-4 illustrate use of a short section of chain grate stoker arranged to feed waste into the furnace with a long section of chain grate stoker to provide for residence burning.

Each of the sections can be separately controlled to adjust feed and burning rates as needed. The underfire air supply to each section is also individual controlled. A three-section reciprocating stoker assembly is shown installed in an incinerator, Attachment 10-6, with a water-walled furnace, at the Norfolk Navy Base, Norfolk, Virginia (9).

Other types of grates are employed in which sections may be oscillated or rolled to provide a tumbling action which agitates the waste. This tumbling action is especially desirable since waste tends to burn from the upper surface down and also tends to mat in a manner which interferes with proper air flow.

Oscillating grates and barrel grates are shown in Attachments 10-7 (a,b).

There are other types of grate assembly but all attempt to provide a feeder section which also serves to begin the waste drying, followed by one or more sections of grate to provide for complete refuse burnout. Multiple-section units are usually longer than they are wide. One design, the Martin Grate (9), is wider than it is long and has only one section. This unit agitates the fuel bed through a "reverse" reciprocating action. Local motion tends to drive the refuse up the slope of the stoker assembly, thus achieving a tumbling action.

In general, the use of continuous feed has become common enough to be considered a "standard" configuration, and the rate of feed is based on an energy release criterion of 300,000 Btu/hr ft^2. For a "typical" waste with 5,000 Btu/lb energy content this corresponds to a 60 lb/hr ft^2 mass feed rate. Combined with an energy release design of 20,000 Btu/hr ft^3, the area factor establishes the physical volume of furnace needed for a specified type and quantity of waste. Example 10.1 illustrates use of these rule of thumb.

Example 10.1:

Determine grate area and furnace volume required to burn 40 *ton/hr* of 10 million Btu/ton solid waste:

$$\begin{aligned} \textit{Energy Input Rate} &= 40\ ton/hr \times 10 \times 10^6\ Btu/ton \\ &= 400 \times 10^6 Btu/hr \\ \textit{Grate Area Needed} &= \frac{400 \times 10^6 Btu/hr}{300 \times 10^3 Btu/hr\ ft^2} \\ &= 1330\ ft^2 \\ \textit{Volume needed} &= \frac{400 \times 10^6 Btu/hr}{20 \times 10^3 Btu/hr\ ft^3} \\ &= 20{,}000\ ft^3 \end{aligned}$$

Furnace design is influenced by a number of factors, including whether or not the walls are cooled, and what cooling medium is used. Uncooled refractory-wall incinerators usually require 200 or 400 percent excess air to prevent excessive furnace temperatures which may damage the refractory. With air-cooled walls, constructed by locating tuyeres in either a silicon carbide brick or special cast iron side wall structure, excess air can be reduced to approximately 150 percent. Water-cooled walls, as used in modern water-walled steam generators (Attachment 10-6) allow operation with only 50 percent excess air. The quantity of excess air is especially relevant to air pollution control, because the NO_x and total gas to be handled by any cleanup technique escalates with increasing excess air. Consequently, the size and operating costs for fans, ducts, and air quality control devices become larger as excess air increases. Pumping power also increases proportionately, assuming other factors remain constant. The reduced excess air requirement clearly explains why steam-raising incinerators, with water-walled furnaces, are more desirable than either air-cooled or plain refractory-walled units—aside from energy recovery considerations.

Corrosion, however, can be a significant problem in steam-raising incinerators where metal temperatures are above 500°F (11). Since superheaters usually operate at temperatures above 700°F, special care will be required to avoid significant corrosion.

Air Quality Control Considerations

Municipal incinerators are sources of both gaseous and particulate pollution and can be indirectly responsible for water pollution as well, since water is used to quench residues before their removal from the incinerator. In general, residue quench water will be alkaline. Water from spray chambers or scrubbers will be acidic, as a direct consequence of the vinyl chloride plastics found in waste. Water also may be used in sprays to cool effluent gases. In wet scrubbers it is employed to remove both particulate and gases. Work has been done in an operating incinerator (12) that indicates HCl emission increases with increasing plastic content, but that wet scrubbing can remove from 80 to 90 percent of this gaseous pollutant.

Here again, there is an evolving "state of the art," and no optimum method has yet emerged. Municipal incinerator (50 T/D) standards for new sources (13) limit particulate emission to 0.08 gr/scf at 12 percent CO_2. Electrostatic precipitators have been installed on new designs with the expectation that they can meet the standard. Electrostatic precipitators normally operate at temperatures between 275°F and 550°F. When precipitators are applied to steam-raising incinerators, whether of waste heat boiler type or full water-walled steam generator design, the lower temperature typically is specified. Incinerators without heat recovery, however, require cooling of gases from temperatures of 1,200°F to 500°F. This is accomplished in one of several ways:

1. Gas cooling through the addition of ambient air;
2. Water sprays to cool the gases;
3. A combination of added air and water sprays.

Adding air alone significantly increases physical volume, which means larger fans and greater power. Water by itself can result in a water carryover to the precipitator. Method three usually represents a reasonable compromise.

Venturi-type high-energy wet scrubbers show promise, but require considerable power and therefore have high operating costs. Scrubber efficiencies of 99 percent can be achieved if a pressure drop of 40 to 50 inches of water column can be tolerated. Wet scrubbers operate with water ph as low as 1.6, which means corrosion is also a problem. Water treatment must be provided, producing additional first-cost and operating cost. This is not a serious disadvantage where an incinerator can be located near a municipal waste water treatment facility, as has been reported (17)—but this is not an arrangement which is ordinarily possible. Wet scrubbers have the serious disadvantage of poor plume bouyancy. Gas leaves the scrubber at a temperature in the range of 165°F to 175°F and forms a visible plume due to water vapor. The poor plume bouyancy means a short stack is undesirable. Reheating flue gases after scrubbing by employing hot unscrubbed gases is one possible solution to this problem, but it is one which complicates both hardware design and operation. Where scrubbers are added as a retrofit, this reheat requirement can reduce furnace capacity.

Baghouses do not appear to be in favor with designers of modern incinerators, most likely because of economic reasons.

Economics

The reported costs, both capital and operating, are high. Refractory-walled, non-energy recovery units have ranged in capital costs from a low of $4,000 to a high of $12,000 per ton of capacity. Energy recovery water-walled units range from $15,000 for large units to $30,000 per ton for small (150 to 300 T/D) steam-raising units. Operating costs also show a wide variation, depending on incinerator type, location, and mode of operation. Where units are located within city business areas to provide energy for municipal buildings, as in Harrisburg, Pennsylvania and Nashville, Tennessee, costs reflect the site choice. A modern energy recovery incinerator is a high-technology undertaking when properly designed, and can be expected to become more so as development continues.

Wood and Wood Wastes

Wood and wood wastes are similar to municipal solid waste with metal, glass, and ash removed. Noting the high paper content (see Attachment 3-13), this similarity is not surprising, since papers are largely cellulose—derived from wood. A comparison of the ultimate analysis presented in Table 10.1, with those for wood and wood wastes given in Attachments 3-10 and 3-11, would suggest similar air requirements relative to both quantity and distribution.

The high volatile matter content of these fuels means very little of the combustible will burn on grates. Therefore, the air supply must be divided between underfire air and overfire air jets, and each separately controlled. Wood wastes produce ash different from that which can be expected from "white" wood because of handling. Hogged fuel is made up of bark and nonuseful wood scraps which may contain considerable dirt and grit. Where logs are salt-water stored, bark will contain considerable salt which will be emitted in the stack plume.

Spreader stoker feed of either solid or wood wastes can produce higher particulate loading than those from the suspension burning of coal. This elevated loading derives from the density of wood, compared with that of coal. Woods vary in density, with specific gravity as low as 0.1, but typically 0.3 to 0.5. Because the settling velocity of a particle is proportional to its density, particles would either settle out or be removed. Residence times for wood and solid waste range from 2 to 4.5 seconds (14), compared with 1 to 2 seconds for oil and pulverized coal. Particles with a mean diameter on the order of one mm will not be consumed in this time, and therefore leave as a fragment of char. Where fuel preparation (usually a hogging operation) produces a large fraction of particles in the one mm range, particulate loading will be greater for equipment fired by air spreaders.

Typical Wood Burning Equipment

Wood, wood waste and solid waste firing arrangements are similar. Dutch ovens with waste heat boilers (Attachment 10-8) illustrate the use of a separate volatizing region where fuel enters from above. Combustion air enters as primary air under the grates, with secondary air entering through ports in the bridge wall at a point just beneath the drop-nose arch.

The fuel cell illustrated in Attachment 10-9 is a variation of the Dutch oven design. It differs in its method of air introduction. A volatizing region is surrounded with an annulus through which the overfire air flows. Air is preheated as it flows through the passage way. This design does not use separate forced draft fans to supply underfire and overfire air.

Attachments 10-10, 10-11, and 10-12 illustrate modern designs using inclined water-cooled grates and pneumatic spreaders. Note the use of an uncooled refractory section at the entry region of the inclined grate. This is the drying or volatizing zone and the furnace has an arch above it to deflect gases to the region over the hottest part of the fuel bed. In some designs arches are used at the burnout end of travelling grates to radiate energy down onto the fuel bed at the place where little fuel remains in the ash.

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17. Backus, E. S., "Incinerator Designed to Anticipate Problems," *Public Works,* April 1971, p.79, (April 1971).
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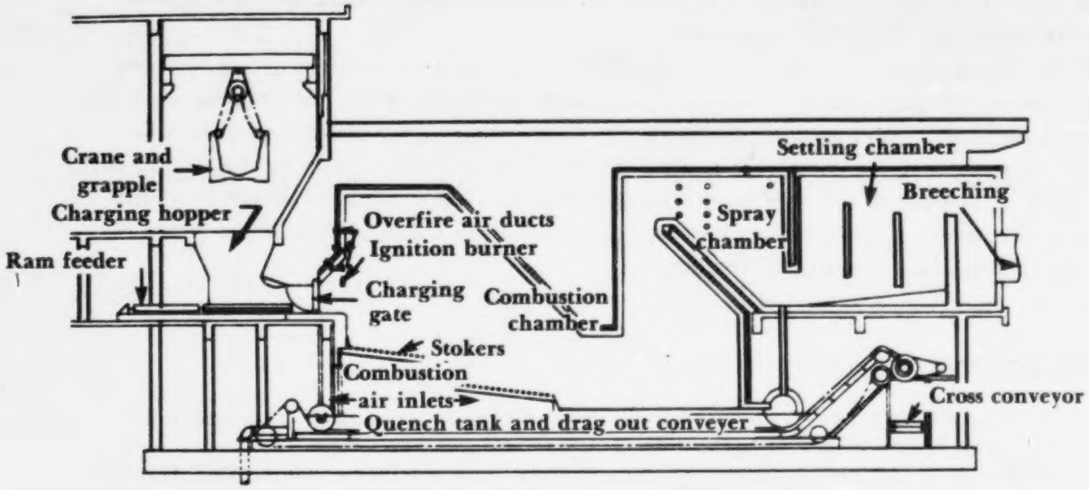
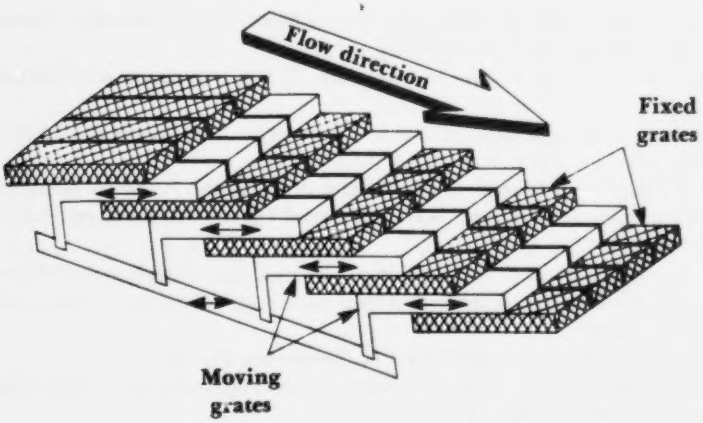
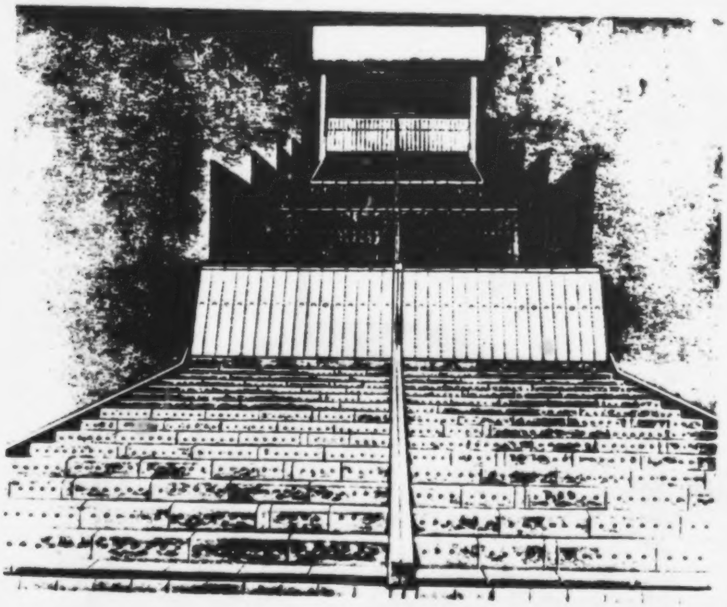
Attachment 10-1. Cross section of ram-fed incinerator[9]


Crane and grapple
Charging hopper
Ram feeder
Overfire air ducts
Ignition burner
Charging gate
Combustion chamber
Stokers
Combustion air inlets
Quench tank and drag out conveyer
Settling chamber
Spray chamber
Breeching
Cross conveyor

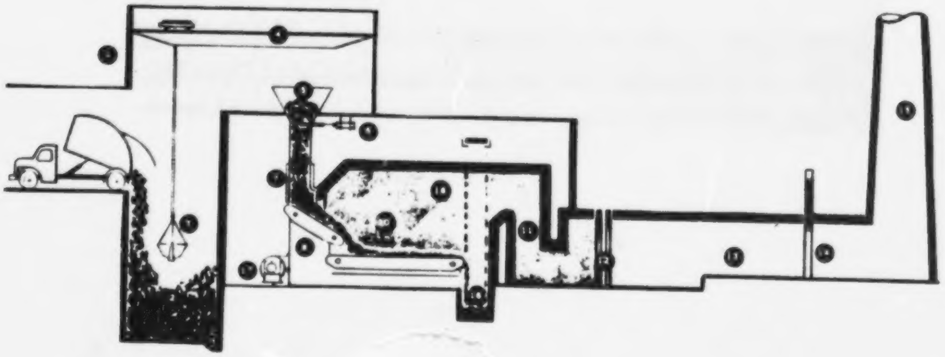
Attachment 10-2. Schematic of reciprocating grates[10]


Flow direction
Fixed grates
Moving grates

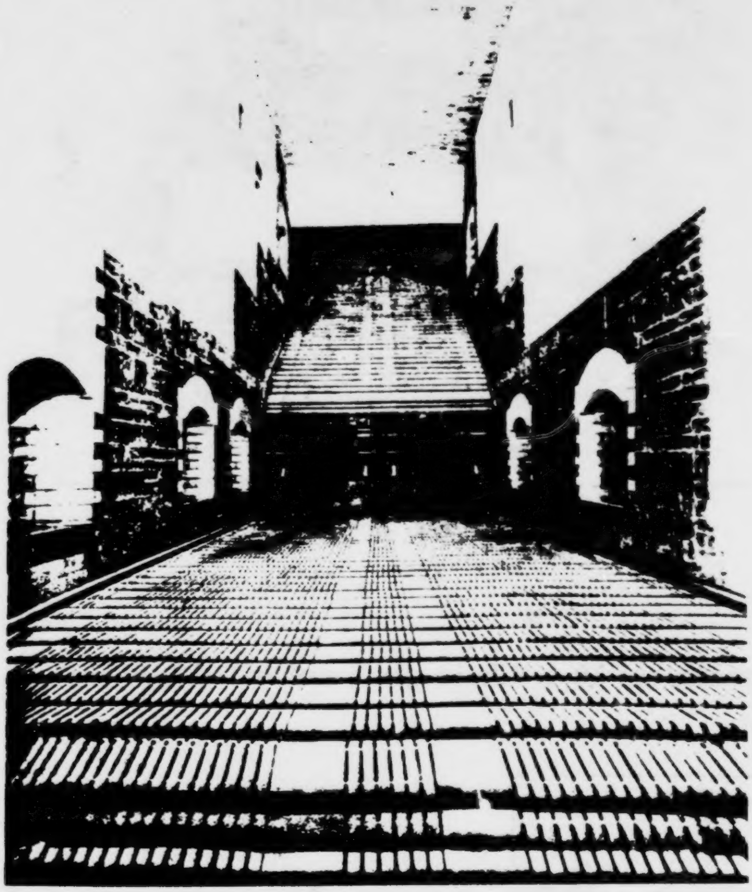
Attachment 10-3. Front view of reciprocating grate stoker[9]



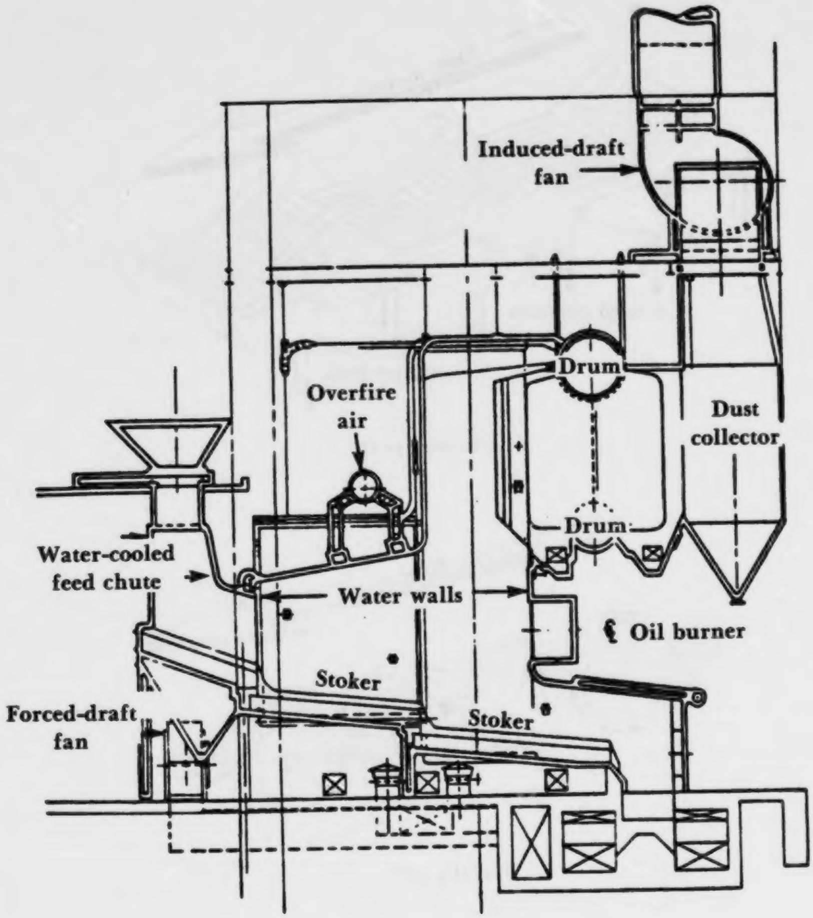
Attachment 10-4. Chain grate stoker-fed furnace[9]



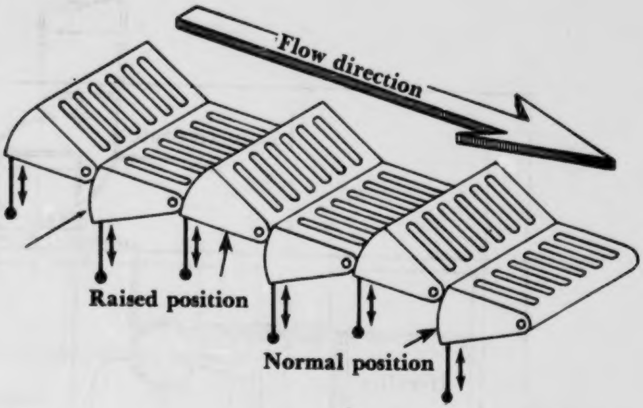
Attachment 10-5. Chain-grate stoker[9]



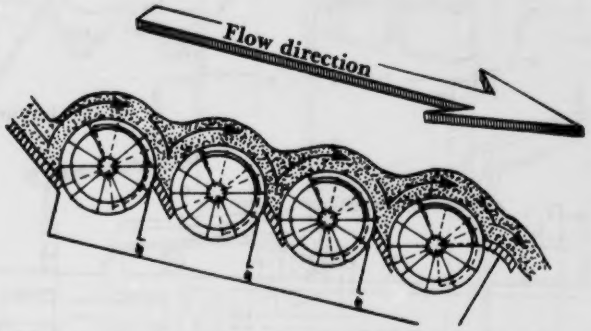
Attachment 10-6. Reciprocating stoker in a water-wall furnace[9]


Induced-draft fan
Drum
Overfire air
Dust collector
Drum
Water-cooled feed chute
Water walls
Oil burner
Stoker
Forced-draft fan
Stoker

Attachment 10-7. Oscillating and barrel grates[10]

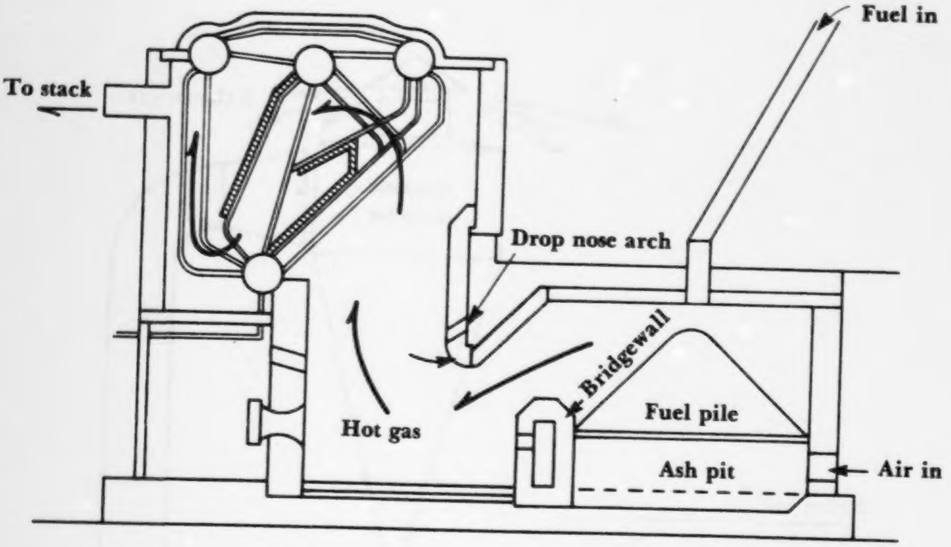

Flow direction
Raised position
Normal position

Oscillating grate

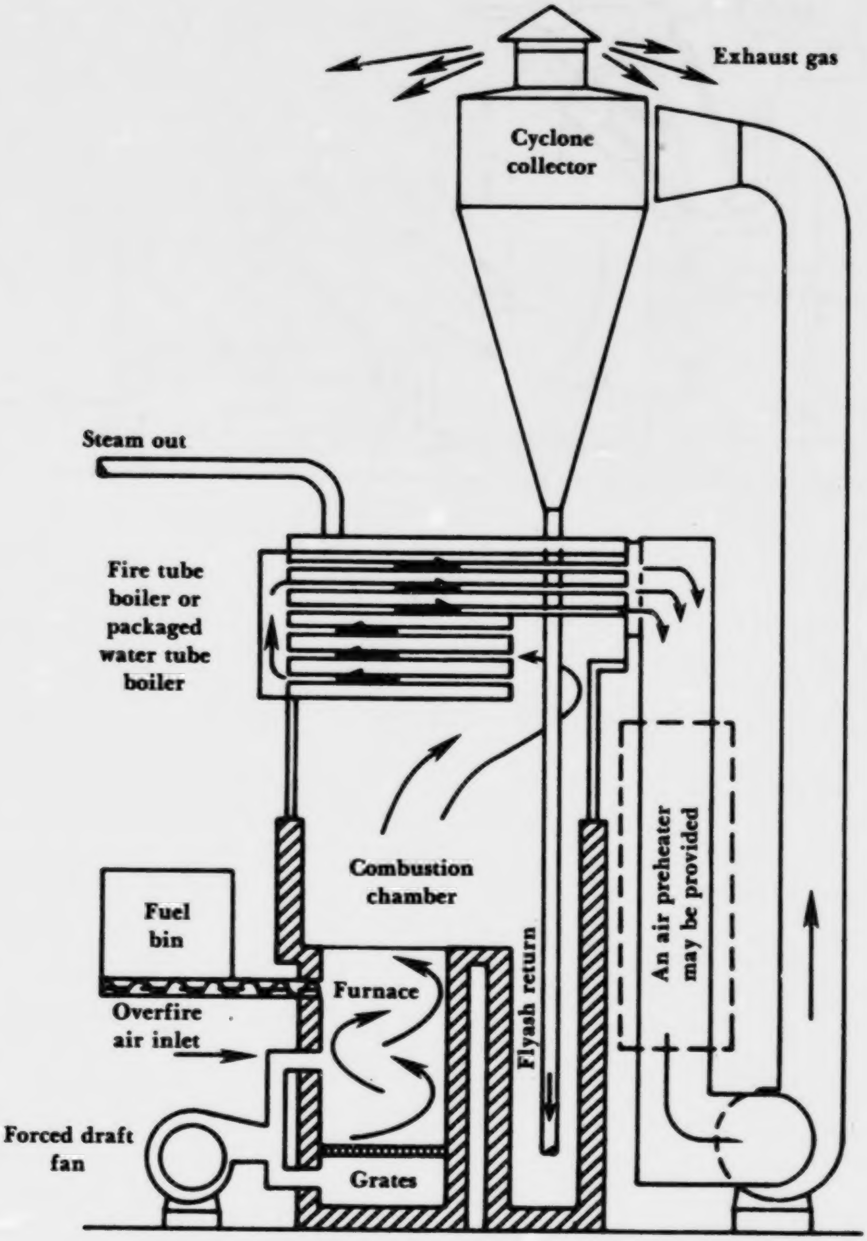

Flow direction

Barrel grate

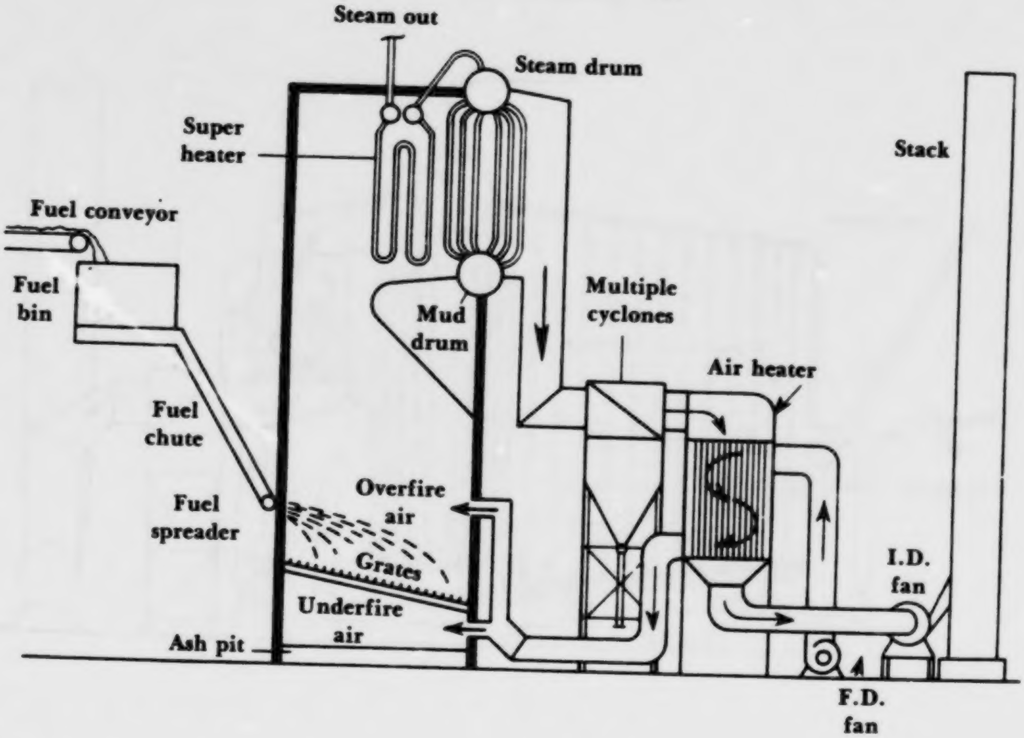
Attachment 10-8. Dutch-oven-fired boiler[15]


Fuel in
To stack
Drop nose arch
Bridgewall
Fuel pile
Hot gas
Ash pit
Air in

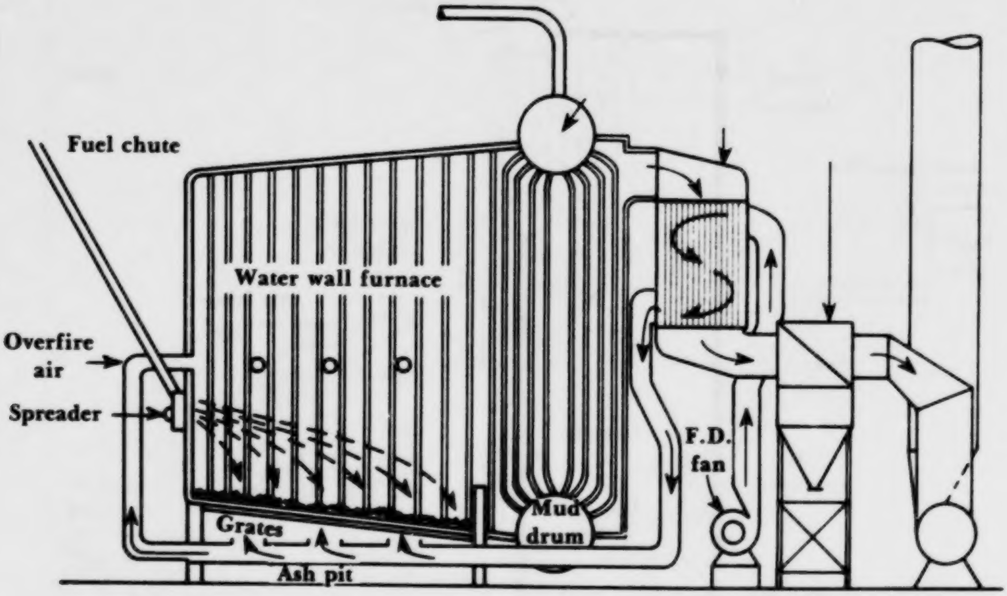
Attachment 10-9. Fuel-cell fired wood waste boiler[15]


Exhaust gas
Cyclone collector
Steam out
Fire tube boiler or packaged water tube boiler
Combustion chamber
Fuel bin
Furnace
Overfire air inlet
Forced draft fan
Grates
Flyash return
An air preheater may be provided

Attachment 10-10. Inclined-grate wood waste fired boiler[15]

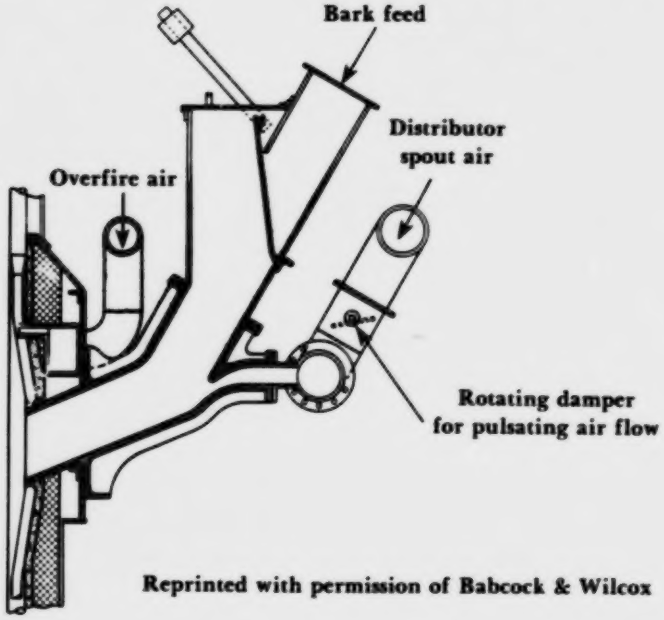

Steam out
Steam drum
Super heater
Stack
Fuel conveyor
Fuel bin
Mud drum
Multiple cyclones
Air heater
Fuel chute
Fuel spreader
Overfire air
Grates
Underfire air
Ash pit
I.D. fan
F.D. fan

Attachment 10-11. Wood waste-fired boiler with air spreader stoker[15]



Fuel chute
Water wall furnace
Overfire air
Spreader
Grates
Ash pit
Mud drum
F.D. fan

Attachment 10-12. Air-swept distributor spout for spreader stoker[18]



Bark feed
Distributor spout air
Overfire air
Rotating damper for pulsating air flow

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Chapter 11

On-site Incineration of Commercial and Industrial Waste

Background Information

The design of small incinerators has undergone considerable change during the last 20 years. Until the mid-1950s backyard incinerators and single-chamber incinerators were very common devices for reducing the volume and weight of solid waste. They were, however, characterized by high smoke, CO, HC, and particulate emissions.

In 1957, the Los Angeles County Air Pollution Control District banned open fires and single-chamber incinerators (Attachment 11-1), because of their contribution to urban air pollution (1). During this period, in New York City, considerable interest focused on the use of auxiliary fuel burners and other design modifications to reduce the emissions from flue-fed apartment house-type incinerators (2). Their combustion problems included a poor ability to control the residence time of the combustion gases, poor turbulence, and low combustion temperatures caused by high excess air. In addition, high emissions resulted from the widespread lack of skilled incinerator operators and by the flue-fed feature which caused overloading and combustion disturbances.

One design for a modified single-chamber flue-fed incinerator is equipped with a roof-mounted afterburner, as illustrated in Attachment 11-2. This modification provides a hinged damper which could be dropped down against the flue-wall during refuse charging. The damper prevents excessive draft and limits combustion gas flow to the roof afterburner during the initial burning stage.

In 1960 the Los Angeles County Air Pollution Control District published design standards for multiple-chamber incinerators (1). The standards established design values for certain velocities, temperatures, and dimensions (see Attachment 11-3), along with procedures for certain standard design calculations. These standards also stressed the importance of operational features, such as refuse-charging method and auxiliary fuel burner requirements. Similar design standards for multiple-chamber incinerators were also published by the Incinerator Institute of America (3).

As shown in Attachment 11-4, multiple-chamber incinerators typically have emissions which are 50% lower than single-chamber units. Among the design improvements were gas speed and directional changes (which increased turbulence), secondary air and auxiliary fuel burners (to improve combustion in the second chamber), larger sizes and damper controls (to provide longer residence time). Barometric dampers required proper design for size to maintain draft at around 0.2 inches of water in the primary chamber. Some multiple-chamber incinerator designs included water scrubbers (Attachment 11-5).

In the 1960s various governmental agencies set emission standards for incinerators which were to be purchased with their funds. In 1969, the Public Health Service established an interim design guide for selection or modification of multiple-chamber incinerators (4). This design guide was to provide control to either 0.2 or 0.3 grains of particulate per standard cubic foot of flue gas, corrected to 12% CO_2. The 0.3 value was for units with burning rates at 200 pounds per hour or less, and the 0.2 value for units rated over 200 pounds per hour. Incinerators sized over 200 pounds per hour required scrubbers.

The 1972 results were presented of stack tests on seven representative, yet fairly new, apartment house incinerators in New York City, Cincinnati, Philadelphia, and Miami (5). The particulate emissions of the two single-chamber units considerably exceeded the Federal standards cited, but the five multiple-chamber units met the standard. Temperatures in the secondary combustion chamber were low, ranging from 650 to 1,145°F—compared with a recommended range of 1,200 to 1,400°F. This indicates too much excess air. Other problems included plugged water spray nozzles, and the inability of some units to operate at their rated capacity.

In the early 1970s, most states considerably tightened their standards for incinerator emissions. This was part of the State Implementation Plans for the Clean Air Amendments of 1970. In many cases the emission standards prohibited typical multiple-chamber incinerators. In fact, because of local sources and ambient conditions, some areas still do not permit new incinerators.

Controlled-Air Incinerators

Controlled-air incinerators are an innovative adaptation of the multiple-chamber incinerator design using forced draft rather than natural draft for the air supply. Because considerably less air is used than for multiple-chamber incinerators, final combustion temperatures are much higher, providing more complete combustion. Also, low combustible particulate loading is achieved by limiting turbulence and air velocities in the primary chamber.

The reduced emissions characteristics of controlled-air incinerators, and of modern municipal incinerators having adequate stack cleaning, have demonstrated adequate emission control for acceptance in most areas.

Although commercial designs have varied with time and manufacturer, the distinguishing design feature is the restrictive control of air supply. As illustrated in Attachment 11-6, a sealed primary chamber acts as a volatilization zone. Air is supplied under the refuse bed at approximately 50% of the stoichiometric value.

Temperature in the primary chamber is controlled to around 1,400°F with the minimum being assured by auxiliary fuel. The maximum may be limited by cutting off the primary air or by the use of water sprays (6, 7). Continuous charging of waste materials generally ensures that less than stoichiometric primary air is present and that a reducing atmosphere will be maintained.

The combustion gases move to a second chamber, or afterburner, for complete oxidation of the smoke, CO, and hydrocarbon gases. The balance of the required air is strategically introduced to provide proper turbulence without quenching the combustible gases. The overall excess air rate may be around 100%. Temperatures in the second chamber are usually controlled at from 1,600 to 1,800°F by the auxiliary fuel and excess air. Typical residence times are from .7 to 1.0 second (8).

Originally "starved-air" units described those with relatively small secondary chambers or afterburners, and "controlled air" units had relatively large secondary chambers. However, today, "controlled air" is used to describe both designs.

Typically controlled-air incinerators are factory manufactured. Each given model has a standardized design and is shipped to the site prepackaged. Loading rates for individual modules are modest with waste rates varying from 400 to 3,000 lb/hr. Larger waste rates are achieved by using multiple numbers of modular units. For example, eight 12.5 T/day units have a combined 100 T/day capability.

Most of the units which have been installed are of the batch type, without continuous ash removal. These units typically operate on a 24-hour cycle, with batch charging at 8- to 10-minute intervals. The full burning rate may be maintained for 7 to 9 hours (7). Then approximately three hours are utilized for burning down the charge with the afterburner operating. Finally, cooling occurs overnight, and in the morning the ash residue is removed. This is followed by preheating the refractory and repeating the daily cycle.

Solid waste weight reduction is around 70%; volume reduction is well over 90%. The amount of auxiliary fuel required for low emissions depends on waste characteristics. Type 0, 1, and 2 waste typically are burned with little auxiliary fuel used during the full burning rate. Of course auxiliary fuel is required for burning down the charge and for preheating the incinerator. Pathological waste may be burned with multiple auxiliary fuel burners in primary as well as secondary chambers.

Most designs have been refined to provide particulate or smoke control adequate to meet most state standards without utilizing a scrubber or other flue gas treatment. Particulate emissions of "dry catch," or the sample collected on or before the filters in EPA sample train, have been recorded from 0.03 to .08 grains per standard cubic foot corrected to 12% CO_2 (7).

Design and Operational Modifications for Improved Performance

The problems inherent in a poorly operating controlled-air incinerator are generally related to either the waste material, charging technique, or the operation of the auxiliary burners.

Higher emissions will occur with the overloading of a unit, because of fly ash entrainment with the higher air velocity in the primary chamber, and the reduced residence time in the second chamber. Emissions also increase as the batch charging disturbs the fire bed. If the charge consists of compressed or packaged materials, rather than loose materials, the rates of volatization and the air delivery can get out of balance and smoke may be observed. Variable moisture in the charge also will cause a combustion imbalance and possible smoking conditions.

The main control method is to modify the charging techniques to cause less disturbance to the fuel bed. Smaller and more frequent charges may be desirable. A design modification that provides a ram feed system with a double-door interlock, illustrated in Attachment 11-8, should avoid the extra air inflow during charging. A more significant design modification would provide continuous feed, fuel-bed agitation, and continuous ash removal. Factory-manufactured controlled-air incinerators are now being marketed with continuous ram feed and ash removal features. These units operate 24 hours per day and thereby have increased loading capability. In addition, the refractory damage due to temperature cycling is considerably reduced.

Reducing the auxiliary fuel used may cut the auxiliary fuel costs, but, of course, the smoke and particulate emissions will probably rise. The automatic controller temperature setting should be adjusted to obtain the proper auxiliary fuel firing rate. Maintenance of burners, refractory walls, and underfire air supply should be done at the intervals recommended by the manufacturer.

A controlled-air incinerator may be abused if it is operated as an excess air incinerator with extra primary air blowers used to increase the energy release rate. Although this modification will cut the afterburner fuel costs, the reduced residence time will increase the smoke and particulates emissions. Maintenance costs may also increase because of the higher temperature cycling of the refractory.

Waste-heat boilers can be provided to produce steam or hot water from stack gas waste energy (7). One design is illustrated in Attachment 11-8. The economics, of course, are most favorable if the refuse waste stream is guaranteed, and if a customer is available who will purchase all the steam or hot water produced. The economic picture for too many major steam-generating solid-waste incinerator facilities has been made difficult by the absence of one or the other of these features.

Incinerator Operation for Minimized Pollutant Emissions

A most important aspect of good minimum-pollutant emission incineration is the way in which it is operated. It must be charged properly in order to reduce fly-ash entrainment and to maintain adequate flame and air conditions. When the charging door of some units is opened, considerable air rushes in and smoke is observed from the stack. Many units are now being designed with ram feeders, as previously described.

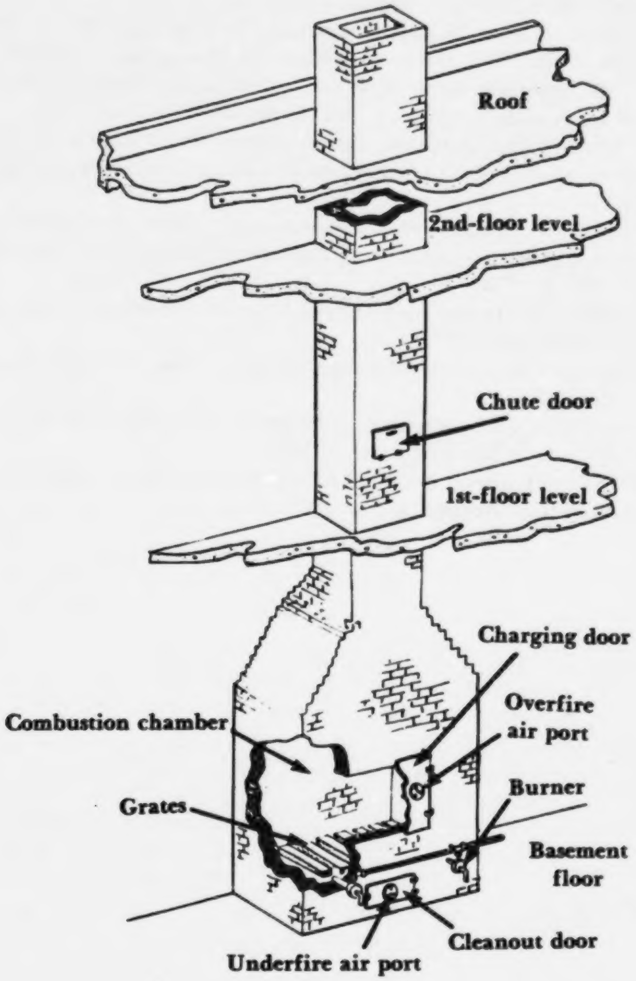
The ignition chamber of multiple-chamber units are normally filled to a depth two-thirds of the distance between the grate and the top arch prior to light-off. After approximately half the refuse has been burned, refuse may be charged with a minimum of disturbance of the fuel bed. The charge should be spread evenly over the grates so that the flame can propagate over the surface of the newly charged material. Variations in underfire and overfire air will give the operator an opportunity to determine the best settings for various types of waste material, depending upon the stack emission.

Auxiliary fuel burners should be started prior to igniting the waste material so that the chamber can be preheated to operating temperature. This will considerably reduce the particulate/smoke emissions.

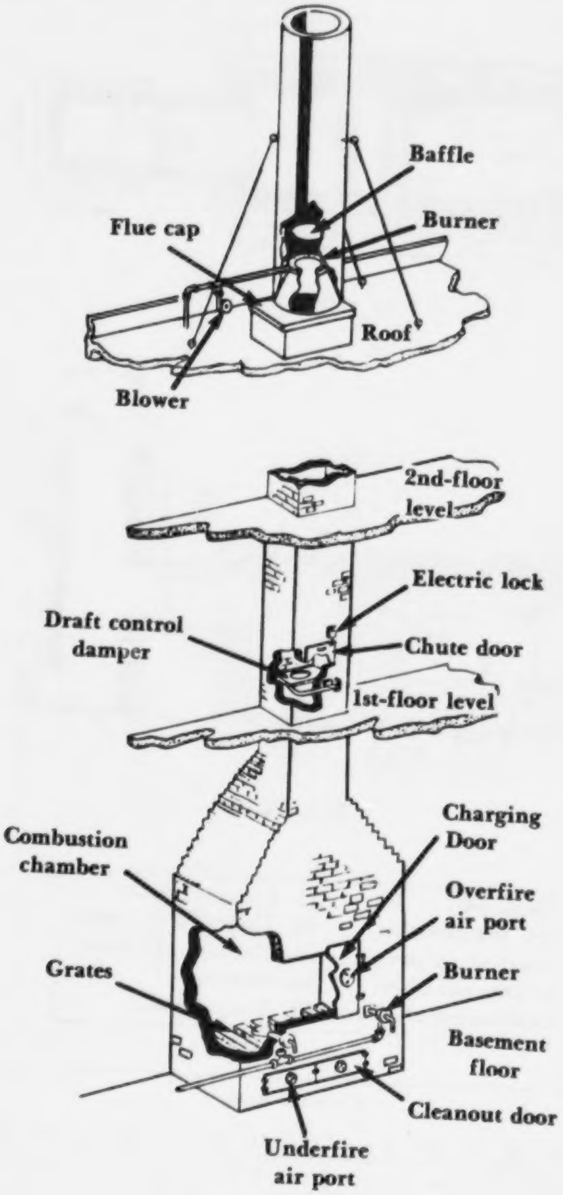
REFERENCES

1. Williamson, J. E., et al., "Multiple-Chamber Incinerator Design Standards for Los Angeles County," Los Angeles County Air Pollution Control District (October 1960).
2. Kaiser, E. R., et al., "Modifications to Reduce Emissions from Flue-Fed Incinerators," New York University, College of Engineering Tech., Report 555.2 (June 1959).
3. "Incinerator Standards," 7th Edition, Incinerator Institute of America, New York (Nov. 1968).
4. "Interim Guide of Good Practice for Incineration at Federal Facilities," AP-46, National Air Pollution Control Administration, Public Health Service, Raleigh, NC (November 1969).
5. Stableski, J. J., Jr., and Cote, W. A., "Air Pollution Emissions from Apartment House Incinerators," *JAPCA*, Vol. 22, No. 4, pp. 239-247 (April 1972).
6. *Incineration, A State of the Art Study*, prepared by National Center for Resources Recovery, Inc., published by Lexington Books, Lexington, Massachusetts, (1974).
7. Hoffman, Ross, "Evaluation of Small Modular Incinerators in Municipal Plants," Final Report of Contract No. 68-01-3171, Office of Solid Waste Management, USEPA (1976).
8. Theoclitus, G., et al., "Concepts and Behavior of Controlled Air Incinerators," *Proceedings of the 1972 National Incinerator Conference*, ASME, pp. 211-216 (June 1972).
9. Smith, L. T., et al., "Emissions Standards and Emissions from Small Scale Solid Waste Incinerators," *Proceedings of 1976 National Waste Processing Conference*, ASME, pp. 203-213 (May 1976).
10. Cross, F. L., and Flower, F. B., "Controlled Air Incinerators," paper presented to Third Annual Environmental Engineering and Science Conference, University of Louisville, Louisville, Kentucky (March 1973).
11. Hoffman, R. E., "Controlled-Air Incineration, Key to Practical Production of Energy from Waste," *Public Works* (September 1976).
12. Danielson, J. A., *Air Pollution Engineering Manual*, Second Edition, U.S. Environmental Protection Agency (May 1973).
13. "Workbook for Operators of Small Boilers and Incinerators," EPA-450/9-76-001, U.S. Environmental Protection Agency (March 1976).
14. "Compilation of Air Pollution Emission Factors," AP-42, Second Edition, Part A, U.S. Environmental Protection Agency (August 1977).

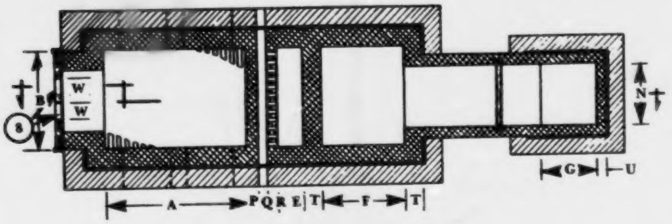
Attachment 11-1. Single-chamber incinerator[12]


Roof
2nd-floor level
Chute door
1st-floor level
Charging door
Combustion chamber
Overfire air port
Burner
Grates
Basement floor
Cleanout door
Underfire air port

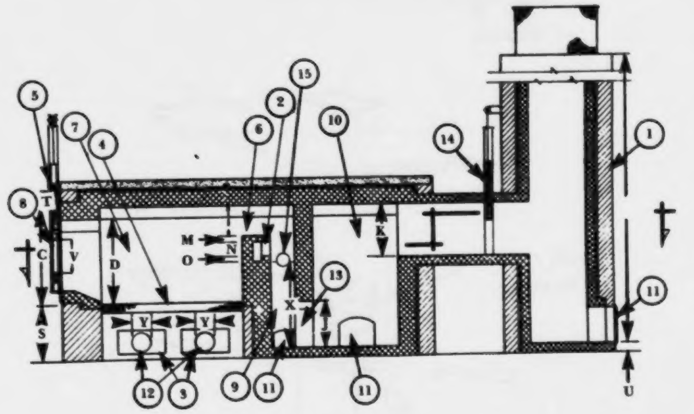
Attachment 11-2. Modified single-chamber flue-fed incinerator[12]


Baffle
Flue cap
Burner
Roof
Blower
2nd-floor level
Electric lock
Draft control damper
Chute door
1st-floor level
Charging Door
Combustion chamber
Overfire air port
Grates
Burner
Basement floor
Cleanout door
Underfire air port

Attachment 11-3. Design standards for multiple-chamber in-line incinerators[1]



Plan view



Side elevation

1. Stack
2. Secondary air ports
3. Ash pit cleanout doors
4. Grates
5. Charging door
6. Flame port
7. Ignition chamber
8. Overfire air ports
9. Mixing chamber
10. Combustion chamber
11. Cleanout doors
12. Underfire air ports
13. Curtain wall port
14. Damper
15. Gas burners

Size of incinerator pounds per hour	Length in inches																								
	A	B	C	D	E	F	G	H	I	J	K	L*	M	N	O	P	Q	R	S	T	U	V	W	X	Y
750	85½	49½	51½	45	15½	54	27	27	9½	24	18	32	4½	5	7½	9	2½	2½	30	9	4½	5	11	51½	7
1000	94½	54	54	47½	18	63	31½	31½	11	29	22½	35	4½	5	10	9	2½	2½	30	9	4½	7	12	52	8
1500	99	76½	65	55	18	72	36	36	12½	32	27	38	4½	5	7½	9	4½	4½	30	9	4½	8	14	61½	9
2000	108	90	69½	57½	22½	79½	40½	40½	15	36	31½	40	4½	5	10	9	4½	4½	30	9	4½	9	15	63½	10
	*Dimension "L" given in feet.																								

Attachment 11-4. Emission factors for refuse incinerators without controls[14].

Incinerator type	Particulates		Sulfur oxides[b]		Carbon monoxide		Hydrocarbons[c]		Nitrogen oxides[d]	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Municipal[e]										
Multiple chamber, uncontrolled	30	15	2.5	1.25	35	17.5	1.5	0.75	3	1.5
With settling chamber and water spray system[f]	14	7	2.5	1.25	35	17.5	1.5	0.75	3	1.5
Industrial/commerical										
Multiple chamber[g]	7	3.5	2.5[h]	1.25	10	5	3	1.5	3	1.5
Single chamber[i]	15	7.5	2.5[h]	1.25	20	10	15	7.5	2	1
Trench[j]										
Wood	13	6.5	0.1[k]	0.05	NA[l]	NA	NA	NA	4	2
Rubber tires	138	69	NA	NA	NA	NA	NA	NA	NA	NA
Municipal refuse	37	18.5	2.5[h]	1.25	NA	NA	NA	NA	NA	NA
Controlled air[m]	1.4	0.7	1.5	0.75	Neg	Neg	Neg	Neg	10	5
Flue-fed single chamber[n]	30	15	0.5	0.25	20	10	15	7.5	3	1.5
Flue-fed (modified)[o,p]	6	3	0.5	0.25	10	5	3	1.5	10	5
Domestic single chamber										
Without primary burner[q]	35	17.5	0.5	0.25	300	150	100	50	1	0.5
With primary burner[r]	7	3.5	0.5	0.25	Neg	Neg	2	1	2	1
Pathological[s]	8	4	Neg	Neg	Neg	Neg	Neg	Neg	3	1.5

[a] Average factors given based on EPA procedures for incinerator stack testing.

[b] Expressed as sulfur dioxide.

[c] Expressed as methane.

[d] Expressed as nitrogen dioxide.

[e] References 5 and 8 through 14.

[f] Most municipal incinerators are equipped with at least this much control: see Table 2.1-2 for appropriate efficiencies for other controls.

[g] References 3, 5, 10, 13, and 15.

[h] Based on municipal incinerator data.

[i] References 3, 5, 10, and 15.

[j] Reference 7.

[k] Based on data for wood combustion in conical burners.

[l] Not available.

[m] Reference 9.

[n] References 3, 10, 11, 13, 15, and 16.

[o] With afterburners and draft controls.

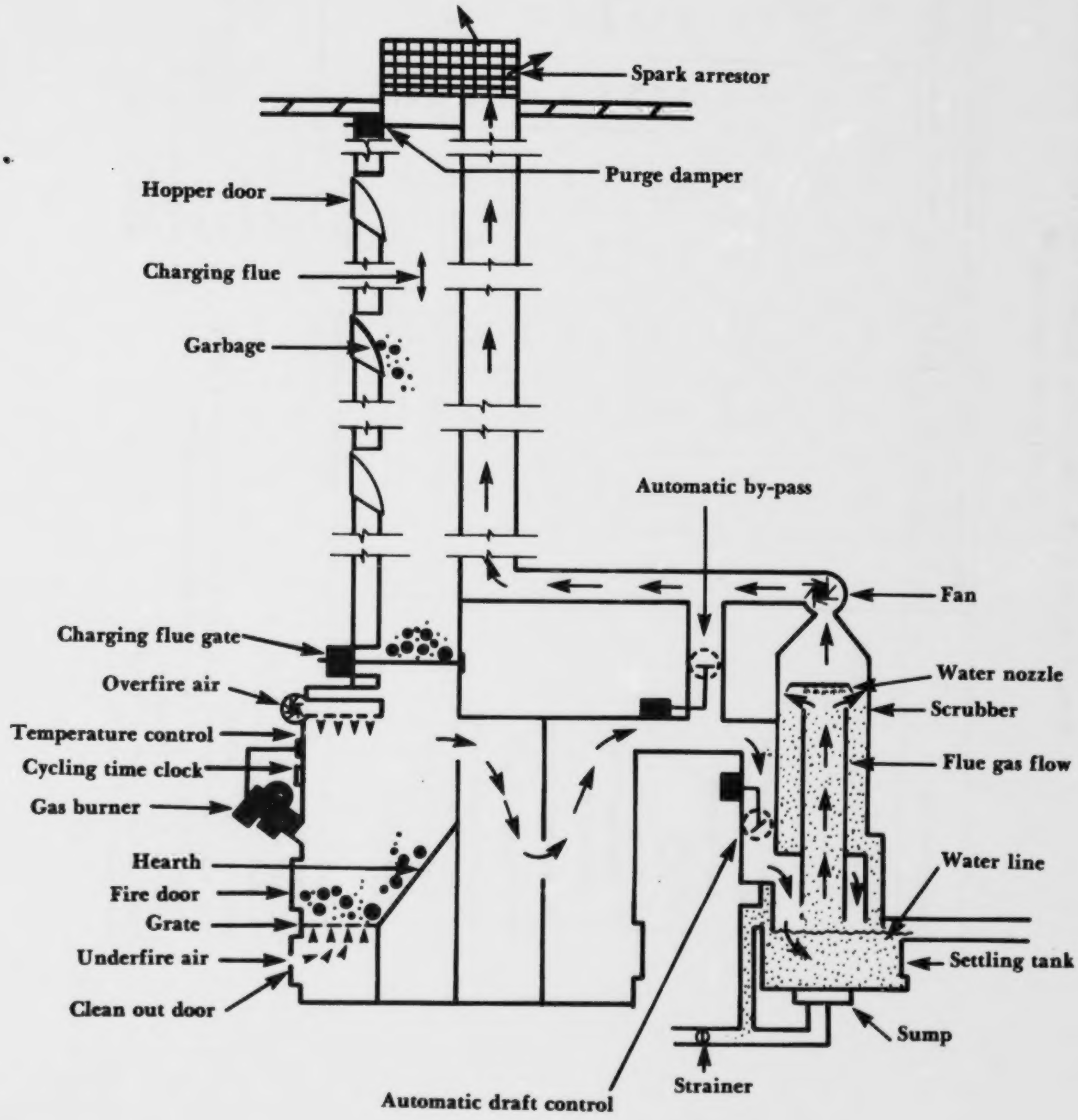
[p] References 3, 11, and 15.

[q] References 5 and 10.

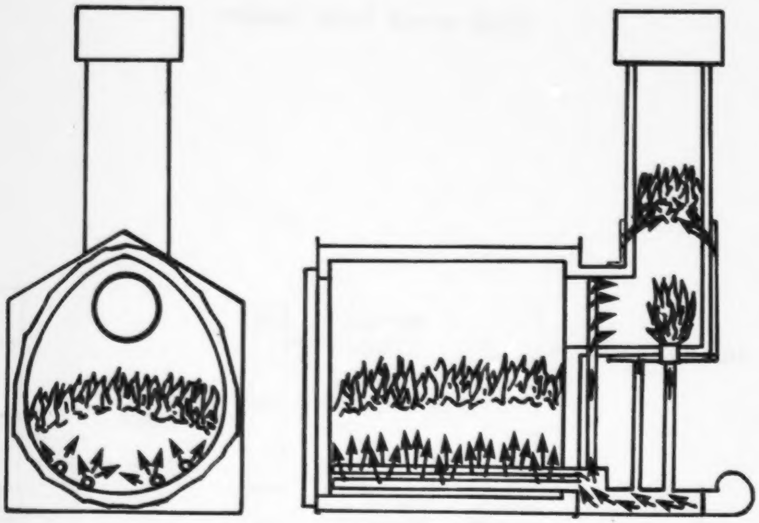
[r] Reference 5.

[s] References 3 and 9.

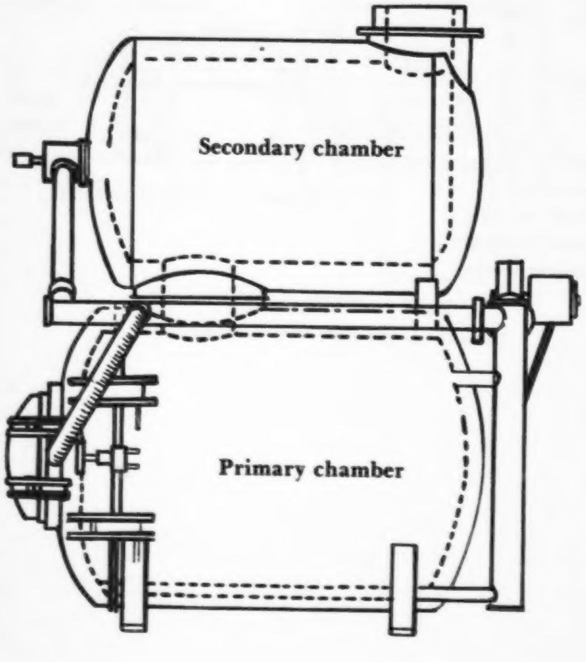
Attachment 11-5. Multiple-chamber flue-fed incinerator with scrubber[13]


Spark arrestor
Purge damper
Hopper door
Charging flue
Garbage
Automatic by-pass
Fan
Charging flue gate
Water nozzle
Overfire air
Scrubber
Temperature control
Flue gas flow
Cycling time clock
Gas burner
Hearth
Water line
Fire door
Grate
Settling tank
Underfire air
Clean out door
Sump
Strainer
Automatic draft control

Attachment 11-6. Controlled-air incinerator[8]

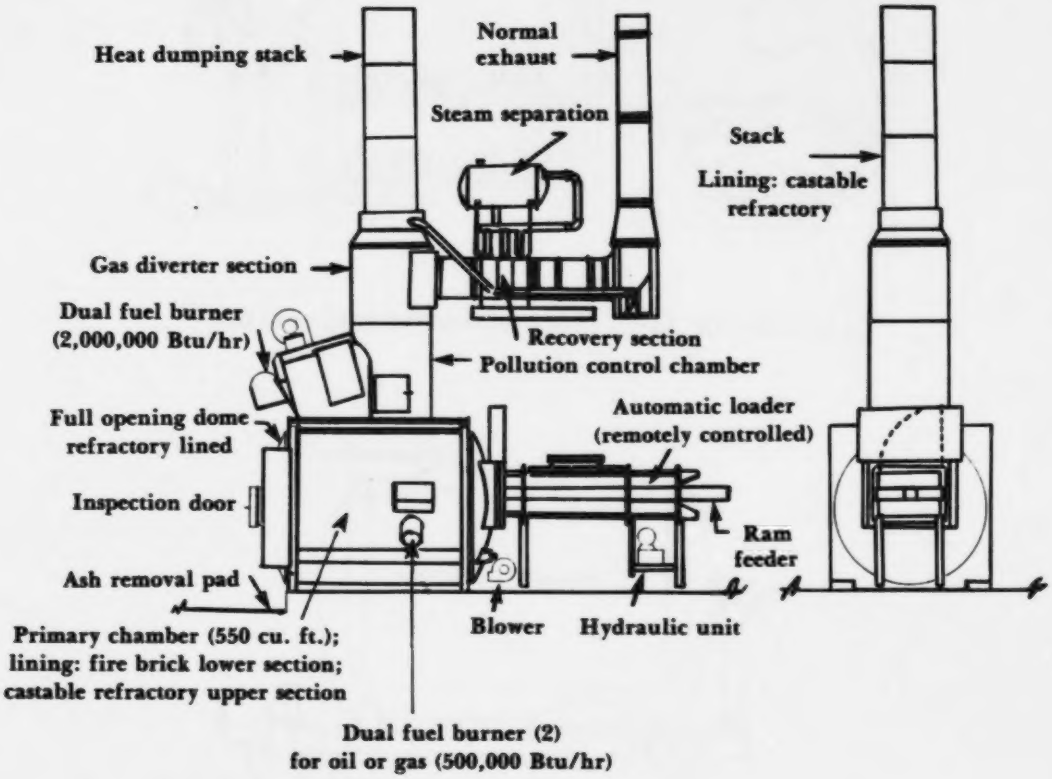


Attachment 11-7. Controlled-air incinerator[10]


Secondary chamber
Primary chamber

Attachment 11-8. Controlled-air incinerator with ram feeder[7]

2nd waste heat boiler


Heat dumping stack
Normal exhaust
Steam separation
Stack
Lining: castable refractory
Gas diverter section
Dual fuel burner (2,000,000 Btu/hr)
Recovery section
Pollution control chamber
Full opening dome refractory lined
Automatic loader (remotely controlled)
Inspection door
Ram feeder
Ash removal pad
Blower
Hydraulic unit
Primary chamber (550 cu. ft.); lining: fire brick lower section; castable refractory upper section
Dual fuel burner (2) for oil or gas (500,000 Btu/hr)

Chapter 12

Municipal Sewage Sludge Incineration

Introduction to Sludge Incineration

Incineration is an acceptable method for volume reduction and sterilization of municipal sewage sludge. Disposing sludge into the ocean depths, in sanitary landfills, and by landspreading have been widely practiced, but these methods are increasingly subject to environmental concern. Ocean dumping has an apparent adverse effect upon life on the sea floor (1). Landspreading disposal is of concern because of aesthetic and health reasons. Every year there are even fewer acceptable sites available.

On-site sludge incineration may have certain economic advantages related to automation (labor costs) and transportation. However, the moisture content of typical sewage sludge is such that considerable auxiliary fuel is required.

Air pollution emissions from sludge incineration vary widely, depending on the sludge being fired, the operating procedures, and the air pollution control device. Particulates may be controlled to the New Source Performance Standards (1.2 lb/ton or 0.65 g/kg dry sludge input) by using a venturi scrubber having approximately 18 inches of water pressure drop. Other acceptable control devices for particulates could be impingement scrubbers, with auxiliary fuel burners (controlled by O_2 sensors), or electrostatic precipitators.

Sludge Characteristics

Typical moisture content for mechanically de-watered sludge ranges from 70 to 80%, depending mainly on the ratio of primary to secondary treatment and the drying equipment used. Notice in Attachment 12-1 that most components of sludge have considerable heating values in their dry form (2).

A sample sludge having 25% solids may contain only enough combustion energy to raise the combustion products and moisture to 900°F. This temperature is far below the 1,350 to 1,400°F necessary for deodorizing the stack gases of a conventional combustion unit. If this sludge were dried (de-watered) to 30% solids, the steady use of auxiliary fuel would be unnecessary. The combustion energy from this sample sludge would heat the combustion products and moisture to the required temperature even after considering the various heat losses (1).

Most of the combustibles present in sludge are volatile, much in the form of grease. The fraction of ash or inert materials depend on the sludge digestion as well as the de-gritting treatment process. Hydrocyclones have been shown to remove up to 95% of the plus 200 to 270 mesh inorganics. This de-gritting process may increase the volatile content of sludge by approximately 10% (1).

A flocculation process used with the clarifying agent in the primary treatment will increase the settling rate and therefore the ratio of primary to secondary sludge. This provides sludge of higher heating content and better de-watering properties.

Wastewater sludges may contain metals which potentially are hazardous if discharged into the atmosphere during incineration. With the exception of mercury, hazardous or potentially hazardous metals (such as cadmium, lead, magnesium, and nickel) will be converted mainly to oxides which will be found in the ash or be removed with the particulates by scrubbers or precipitators.

Mercury is a metal which presents special problems in incineration. In the high temperature region of incinerators, mercury compounds decompose to volatile mercuric oxide or metallic mercury vapor. Mercury concentrations of sewage sludges nationally usually average less than 5 ppm on a dry solid basis but are occasionally as high as 10-15 ppm. For high mercury sludges, greater than 5 ppm dry solid bases, make a mercury balance across the incinerator. Mercury emissions should be held to less than 3200 g/per day.

The above hazardous pollutant standard was established by EPA to limit the atmospheric discharge of mercury from any one site for sewage sludge incinerators.

Lead emissions from sewage incinerators have been less than 10% of their inlet concentrations.

Sludge also may contain toxic pesticides and other organic compounds such as polychlorinated biphenyl (PCBs) usually at low concentration, less than 25 ppm dry solid basis. Such materials are very refractory and may need 800°—1000°C for 0.7 to 1.0 second residence time to approach total destruction. Read chapter 15, incineration of PCBs.

Multiple-Hearth Furnaces

The most widely used sludge incineration system is the multiple-hearth furnace illustrated in Attachment 12-2. The present air-cooled multiple-hearth design is an adaptation of the Herreshoff design of 1889 (4). This design was previously used for roasting ores. In 1935 it was first adapted for sewage sludge incineration with oil-fired auxiliary fuel and manual operation controls (5). Wet scrubbers were added to typical designs in the 1960s, and combustion was improved as automatic controllers became sophisticated in the 1970s.

Multiple-hearth furnaces are in wide use because they are simple and durable and have the ability to burn completely a wide variety of sludge materials, even with fluctuating water content and feed rate. They are most popular in large cities where alternate disposal techniques are inconvenient or too expensive. Over 175 multiple-hearth furnaces were reported operating in 1972 (6).

The typical design features include a cylindrical refractory-lined steel shell having multiple (4 to 12) horizontal solid refractory hearths. Each hearth has an opening that allows the sludge to be dropped to the next lower level and for the gases to pass through in a counterflow direction.

Stoking is provided by a motor-driven revolving central shaft which typically has 2 or 4 "ramble" arms extended over each hearth. "Ramble" teeth are attached to the "ramble" arms and act as ploughs to agitate the sludge material moving it continuously across the hearth to openings for passage to the next lower hearth. This plowing process breaks up lumps and exposes fresh sludge surface area to heat and oxygen.

The central shaft and "ramble" arms are air cooled, in order to prevent damage from the high temperature.

Combustion in multiple-hearth furnaces is typically characterized by four zones. The drying zone is where only moisture is driven off from partially de-watered sludge, by heat transfer from the hot combustion gases. There sludge temperatures are typically increased from room temperature up to 160°F, and the moisture content is reduced from the initial amount (e.g., 75%) down to 45 or 50%. Gases exit this zone at 800 to 900°F. If the gas temperature were to drop to around 500 to 600°F, more auxiliary fuel would be needed in the combustion region; but if it were to increase above 800°F, more excess air would be needed to prevent furnace damage.

The volatization zone is where volatiles are distilled and burned. They have characteristic, long, yellow flames and combustion temperatures of around 1,300 to 1,700°F. Following this zone is the fixed-carbon burning zone, where burning is characterized by short, blue flames. The fourth zone is where the ashes are cooled by heat transfer to the combustion air prior to ash quenching and removal.

The location of the combustion region varies with the sludge feed rate and moisture content, as well as the use of auxiliary fuel. For a given operating condition, if the feed rate or moisture content is reduced, the combustion region may move to a higher hearth. On the other hand, if the feed rate or moisture is increased, the combustion region may move to a lower hearth, because longer drying time is required. Of course, if the combustion zone drops too low, auxiliary fuel burners should provide energy to control the location of the combustion zone and the completeness of combustion.

Combustion control systems may include temperature-indicating controllers, proportionate fuel burners (with electric ignition), ultraviolet scanners, motorized valves in air headers, automatic draft control, and a controller driven by a flue gas oxygen analyzer.

The amount of excess air is important for assuring odor control and complete combustion. Insufficient combustion air results in smoke emitted from furnace doors as well as stack. However, too much excess air also may act to reduce the normal combustion temperature, thereby causing increased auxiliary fuel usage. Typically the excess air rate is between 50 and 125%.

Attachment 12-2 illustrates the cooling air from the central shaft and "ramble" arms which may be from 350 to 400°F. This air may be used as preheated combustion air or as reheat energy to aid in dissipating the plume associated with the wet scrubbers.

Hot flue gases leaving the incinerator are typically cooled by water sprays, air dilution, or energy recovery heat transfer prior to arriving at the scrubber. The cleaned gases may then be reheated by an afterburner or by heat exchange to assist in plume dispersion. Other uses of flue gas waste heat may be for preheating combustion air, for building environmental control, or for thermal conditioning of sewage sludge to reduce moisture. Although multiple-hearth furnaces are capable of continuous operation, many units have been oversized and operate on an intermittent schedule. The cyclic temperature variations must be tempered by auxiliary heating to limit the possible structural damage caused by thermal stresses. In addition, the furnace must be preheated prior to the beginning of sludge incineration in order to prevent smoke and odor problems. Thermal losses from shut down and restart may account for as much as 80% of the auxiliary fuel demand (1).

Fluidized-Bed Combustion

Fluidized-bed technology has been developed primarily by the petro-chemical industry. The method has been proved for various applications: catalyst recovery in oil refining, metallurgical roasting, spent sulfite liquor combustion, and the incineration of wood wastes, as well as municipal and industrial sludges. Considerable demonstrations also have shown the application of fluidized-bed combustion to electric and steam energy production by burning coal.

Typical cross sections of fluidized bed combustion units (reactors) for sewage sludge are found in Attachments 12-3 and 12-4. Bed material is composed of graded silica sand. Air is directed upward through the bed at a flow rate calibrated to cause the bed to be fluidized, resembling rapid boiling agitation.

Sludge is fed in only after the bed has been preheated by auxiliary fuel to around 1,400°F to avoid improper combustion and odor problems. Fuel sludge may be introduced directly onto the bed through pipes in the wide wall or through spray nozzles above the bed at the top of the disengagement zone. In the latter case, water is vaporized from the sludge in the disengagement zone by heat transfer from the hot combustion gases.

Thermal oxidation of sludge solids occurs in the hot fluidized bed due to the mixing of air and combustible materials. Heat transfer between the solids and gases is rapid because of the large surface area available. Although the bed may glow and incandescent sparks may be seen above the bed, there is no flame.

The heat required for raising sludge to the kindling point must come from the hot fluidized bed which must have a volume of adequate size to act as stabilizing heat sink. The disengagement zone above the bed permits larger entrained solid particles to settle out for burnup in the fluidized bed.

The bed retains organic particles until they are essentially reduced to ash. The bed agitation prevents the buildup of clinkers. Ash is removed through the entrainment of small particles by the combustion gases. These particulates must be adequately controlled by a scrubber or some other collective device.

As in multiple-hearth furnaces, the amount of auxiliary fuel used depends on the properties of the sludge and the operating conditions.

The operating temperatures and excess air requirements for fluidized bed combustion are low, so that NO_X formation is modest. Sufficient air, however, is required to keep the bed (sand) in suspension, but not so great as to carry this sand out of the reactor.

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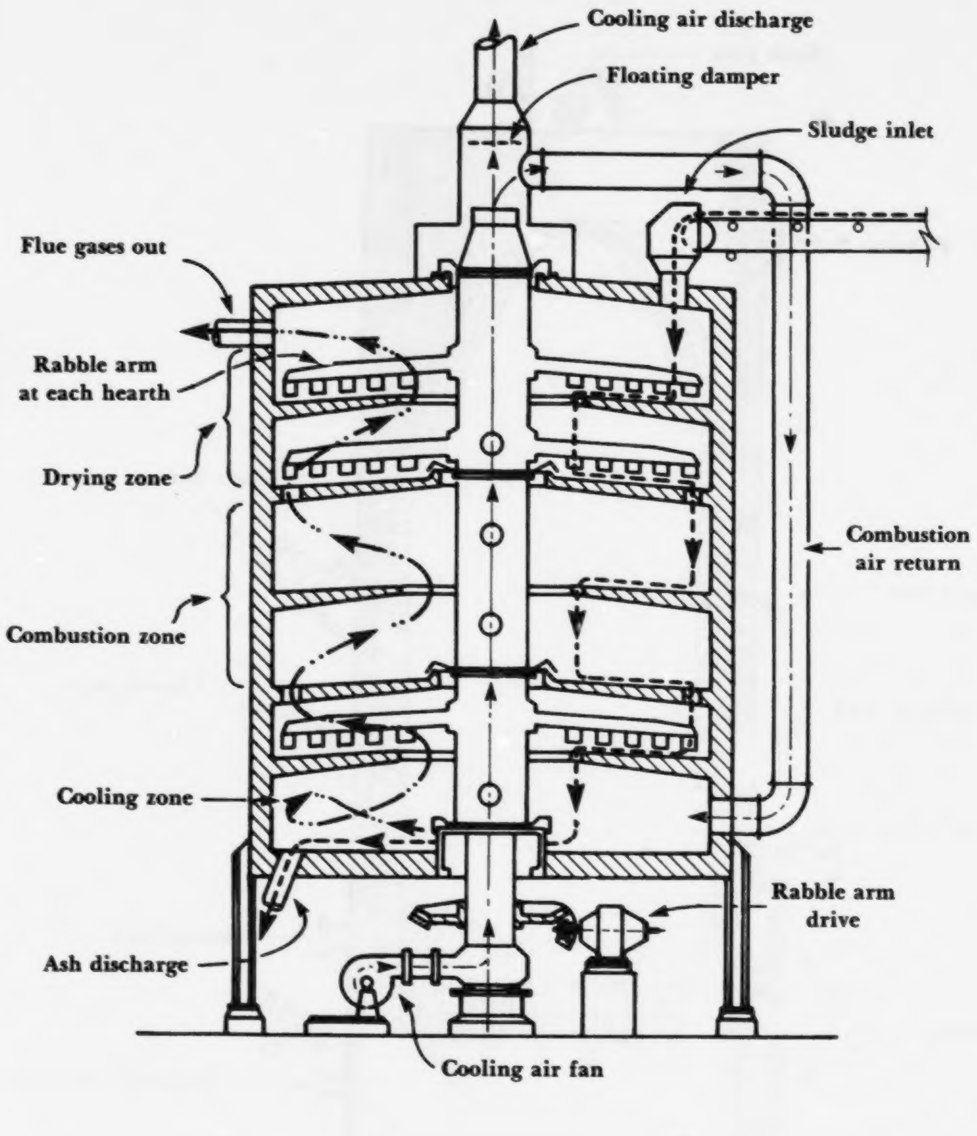
2. "Background Information on National Emission Standards for Hazardous Pollutants – Proposed Amendment to Standards for Asbestos and Mercury," U.S. Environmental Protection Agency, Office of Air and Waste Management, Pub. No. EPA-450/2-74-009a (1974).
3. "Air Pollution Aspects of Sludge Incineration," EPA Technology Transfer Seminar Publication, EPA-625/4-75-009 (June 1975).
4. Unterberg, W., et al., "Component Cost for Multiple-Hearth Sludge Incineration from Field Data," *Proceedings of the 1974 National Incinerator Conference*, ASME, pp. 289-309 (May 1974).
5. Burd, R. S., "A Study of Sludge Handling and Disposal," U.S. Dept. of Interior, Federal Water Pollution Control Administration, Publication No. WP-20-4 (May 1968).
6. Cardinal, P. J., Jr., and Sebastian, F. P., "Operation, Control, and Ambient Air Quality Considerations in Modern Multiple Hearth Incinerators," *Proceedings of 1972 National Incinerator Conference*, ASME, pp. 290-299 (June 1972).
7. Fair, G. M., et al., *Elements of Water Supply and Wastewater Disposal*, 2nd Edition, John Wiley and Sons, New York (1971).
8. Petura, R. C., "Operating Characteristics and Emission Performance of Multiple Hearth Furnaces with Sewer Sludge," *Proceedings of 1976 National Waste Processing Conference*, ASME, pp. 117-124 (May 1976).

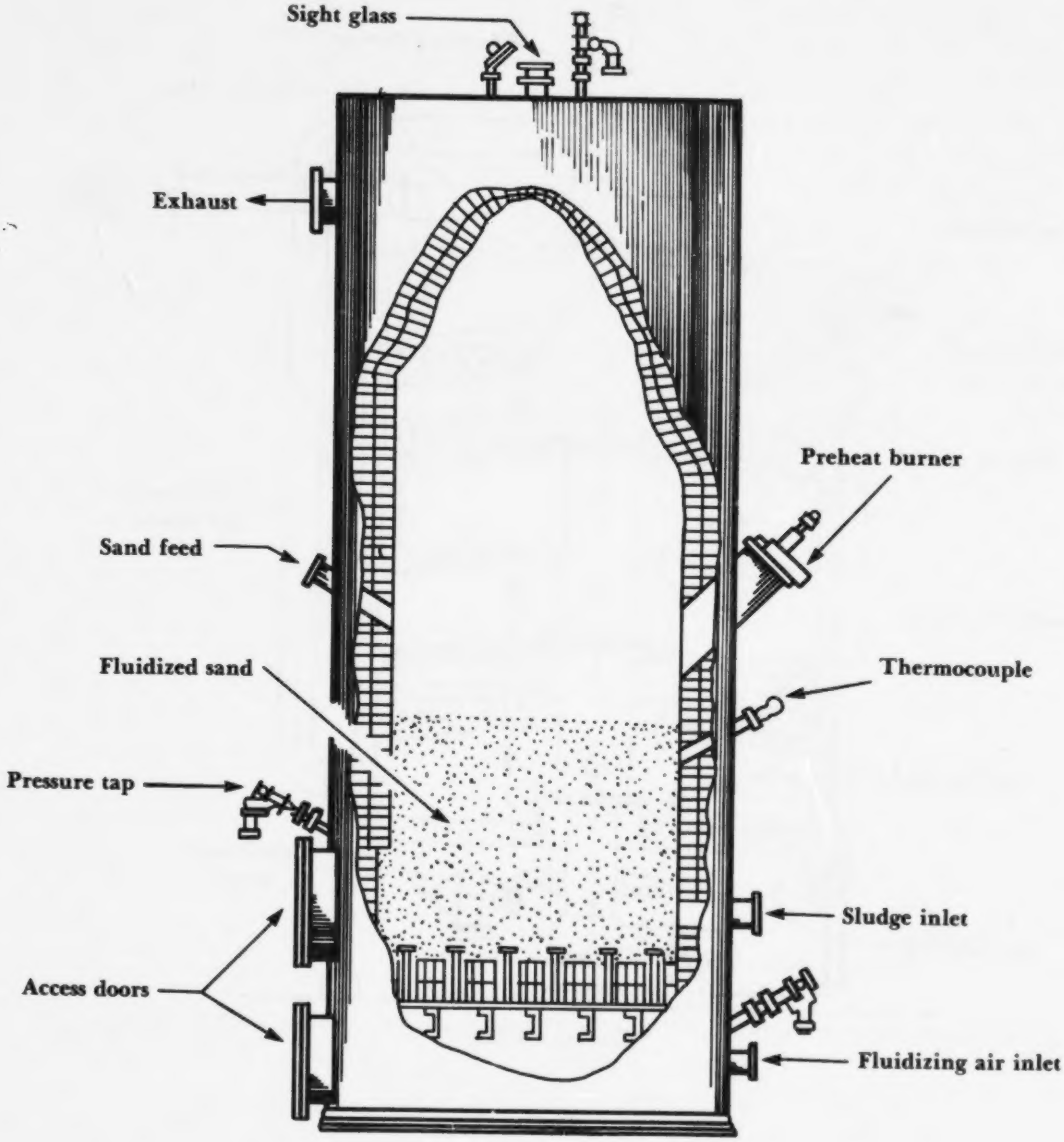
Attachment 12-1. Average characteristics of sewage sludge[2]

Material	Combustibles (%)	Ash (%)	Heat content (cal/g)	Heat content (Btu/lb)
Grease and scum	88.5	11.5	9300	(16,750)
Raw sewage solids	74.0	26.0	5710	(10,285)
Fine screenings	86.4	13.6	4990	(8,990)
Ground garbage	84.8	15.2	4580	(8,245)
Digested sewage solids and ground garbage	49.6	50.4	4450	(8,020)
Digested sludge	59.6	40.4	2940	(5,290)
Grit	30.2	69.8	220	(4,000)

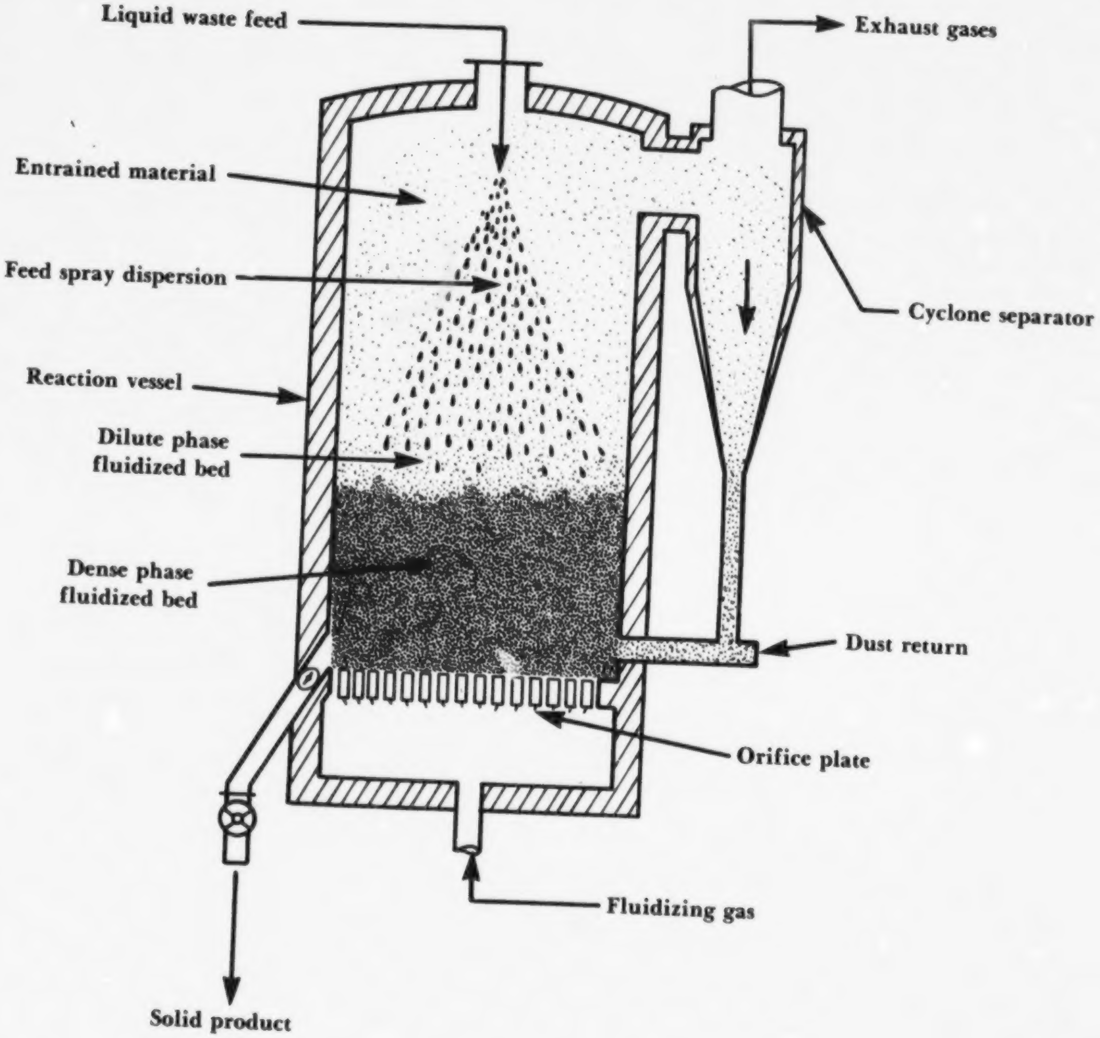
Attachment 12-2. Typical section of multiple-hearth incinerator[5]


Cooling air discharge
Floating damper
Sludge inlet
Flue gases out
Rabble arm at each hearth
Drying zone
Combustion zone
Combustion air return
Cooling zone
Rabble arm drive
Ash discharge
Cooling air fan

Attachment 12-3. Typical section of a fluid-bed reactor[1]


Sight glass
Exhaust
Preheat burner
Sand feed
Fluidized sand
Thermocouple
Pressure tap
Sludge inlet
Access doors
Fluidizing air inlet

Attachment 12-4. Fluidized bed for sewage sludge incineration


Liquid waste feed
Exhaust gases
Entrained material
Feed spray dispersion
Cyclone separator
Reaction vessel
Dilute phase fluidized bed
Dense phase fluidized bed
Dust return
Orifice plate
Fluidizing gas
Solid product

Chapter 13

Direct Flame and Catalytic Incineration

Atmospheric oxidants are primarily the result of a series of chemical reactions between organic compounds and nitrogen oxides in the presence of sunlight. The level of oxidants in the atmosphere depends significantly on the organics initially present, and on the rate at which additional organics are emitted. (The contribution of nitrogen oxides is the subject of Chapter 16 and will not be discussed here.) Photochemical oxidant control strategies are therefore aimed at controlling NO_X and the emissions of volatile organic compounds (VOC) by:

1. Substitution of VOC by solvents of less volatility and lower photochemical reactivity;
2. Process and material changes to reduce VOC emissions;
3. Add-on emission control devices.

The control of objectionable gases and vapors by add-on devices usually relies on one of the following methods:

1. Absorption in a liquid (scrubbing);
2. Adsorption on a solid;
3. Thermal or catalytic incineration;
4. Chemical conversion.

These methods are discussed in detail in another EPA Air Pollution Training Institute Course—#415: Control of Gaseous Emissions. To avoid unnecessary duplication, only those methods which are related to combustion will be outlined here.

The objective of incineration is to oxidize completely the organic vapors and gases from a process or operation that emits them. Some emissions, of course, include particulate as well as gaseous matter. If the particulates are combustible, they may also be handled by the combustion process. Incineration is one of the most widely used methods for controlling VOC emissions from industrial manufacturing processes and from other man-made sources.

Devices in which dilute concentrations of organic vapors are burned by the use of added fuel are known as afterburners. These are capable of handling waste gases which have too low a heating value to maintain sustained combustion. Waste gases with heating values of about 50 Btu/ft^3 or higher can be burned directly without auxiliary fuel in specially designed burners (see Chapter 7). Preheating the gases to 600-700°F may permit direct burning (without auxiliary fuel) of even lower heating value wastes.

The usefulness of afterburners has been well documented. Their popularity has been mainly due to their ease of operation and the availability of low-cost natural gas, at least in the past. Although waste gas incineration is simple in principle, the actual equipment can get somewhat complex due to requirements for controls, as shown in Attachment 13-1.

One of the biggest drawbacks to even wider use of afterburners is the cost of that equipment, especially due to the size needed to handle the large volumes and low concentrations of organics in the various effluent streams. This, coupled with ever-increasing fuel costs and decreasing fuel availability, has raised some serious questions about the continued viability of gas incineration techniques for the control of VOC emissions. Answers to these questions are beyond the scope of this discussion. It should be mentioned, however, that heat recovery devices incorporated in some newer installations are changing the afterburner economics picture considerably as will be discussed later.

The two major types of combustion units are (a) the thermal incinerator and (b) the catalytic incinerator. Catalytic units, a schematic of which is shown in Attachment 13-2, permit the use of a lower temperature than the thermal incinerators for complete combustion, and therefore use less fuel and lighter construction materials. The lower fuel cost can be offset, however, by the added cost of catalysts and typically higher maintenance requirements for the catalytic units.

The physical size of an afterburner is dictated by the volume of the effluent to be treated and the residence or dwell time required at the elevated temperatures. These vary somewhat with the type of effluent, but they are generally in the order of 0.3 to 0.6 seconds at 1,200 to 1,500°F for 99.9+% destruction of organics by thermal incineration. Furthermore, the oxidation requires less time at higher temperatures (see Chapter 2). More detailed information on residence time requirements are found in the appendix to this chapter. Burner type and arrangement have a considerable effect on burning time. The more thorough the flame contact is with the effluent gases, the shorter is the time required to achieve complete combustion. Turbulence in the combustor zone achieves much the same benefit of reducing required retention time, as actual flame contact.

The concentration of combustibles in the fumes to be incinerated cannot exceed 25% of the lower explosive limit (LEL) for safety reasons. This is necessary to avoid any danger of flash-backs to other process units. In practice, it would usually be unwise to attempt to control organic vapors that contain halogens or sulfur solely by combustion, since the combustion products of these elements are even less desirable and often corrosive. A secondary control system, such as a scrubber, may be required in series with the afterburner to remove these contaminants.

The gaseous waste streams usually contain sufficient oxygen for complete combustion of the auxiliary fuel, should the latter be required. An efficient afterburner design can produce complete combustion of the auxiliary fuel with fumes containing as little as 16% by volume of oxygen. The available heat (which is needed to raise the effluent fumes to the incineration temperature) from burning natural gas with 0% outside primary air is considerably higher than the available heats discussed in Chapter 2 and is termed the "hypothetical" available heat. Calculations for fuel requirements using the hypothetical available heat concept are outlined in the *Air Pollution Engineering Manual*, AP-40, on pages 176 and 935 (1).

Using oxygen from the waste gases reduced the auxiliary fuel requirements. Other possibilities for reducing afterburner operating costs include (a) the use of heat recovery devices for preheating incoming fumes or for other plant uses and (b) burning combustible waste liquids through center-fired gun-type burners. A typical regenerative method of heat recovery is illustrated in Attachment 13-3. This particular system operates in a cyclic fashion by switching gas flows from one ceramic bed to another. Continuous operation, without the involved ducting scheme, is possible with a heat wheel. Another frequently used energy-saving approach is the recuperative heat recovery method which is based on continuous heat transfer to another fluid separated by a heat transfer surface. The net cost of using an afterburner to control gaseous pollutants could be reduced further by using the clean, but hot and inert, exhaust gases in some other part of the operation, such as a dryer, etc., if possible.

Commercial afterburner designs are widely available, including systems with heat recovery. Many of these are packaged units with capacities to 3,000 scfm, typically capable of treating the effluent stream at up to 1,500°F for 0.5 seconds. More detailed design and operating conditions can be found in the Appendix and from the references listed at the end of this chapter.

A very readable discussion of the basic principles involved in incinerating combustible gaseous pollutants is available from the book by Edwards (2). Considerable space is devoted there also to catalysts and catalytic devices.

Air Pollution Engineering Manual, AP-40 (1) is oriented more towards specific hardware and actual design and operating characteristics. It contains worked examples of afterburner designs, and an evaluation of an existing afterburner performance.

More detailed calculation procedures are presented by Worley and Motard (3). Modular subroutines were developed which are suitable for inclusion in a larger computer code for Control Equipment Design and Analysis (CEDA) for gaseous pollutants. These subroutines will provide the size of gaseous pollutant control equipment when used in the design mode. In the analysis mode these subroutines are also capable of determining the proper operating conditions for an existing piece of equipment.

A recently completed study of the systems for heat recovery from operating afterburners (4) has concluded that not only are such systems technically feasible, but they can also be economically advantageous. Attachments 13-4 and 13-5 show the magnitudes of energy savings actually being obtained from surveyed operating units.

EPA has issued a series of reports entitled "Control of Volatile Organic Emissions from Existing Stationary Sources" which is directed entirely at the control of volatile organics contributing to the formation of photochemical oxidants. Volume I of this series (5) contains much useful information on the effectiveness and costs of various control options, including both catalytic and non-catalytic (thermal) incinerators. The section of this volume devoted to incineration is reproduced as an Appendix to this chapter. Subsequent volumes of the series deal with the control of VOC from specific industries and processes, and should be consulted for more detailed background and information applicable to a specific problem.

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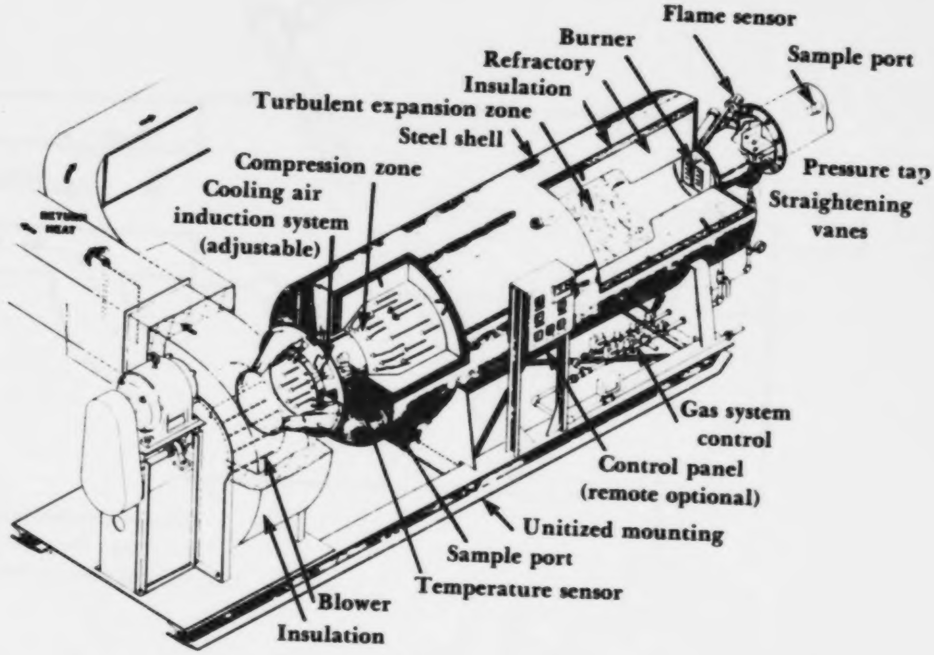
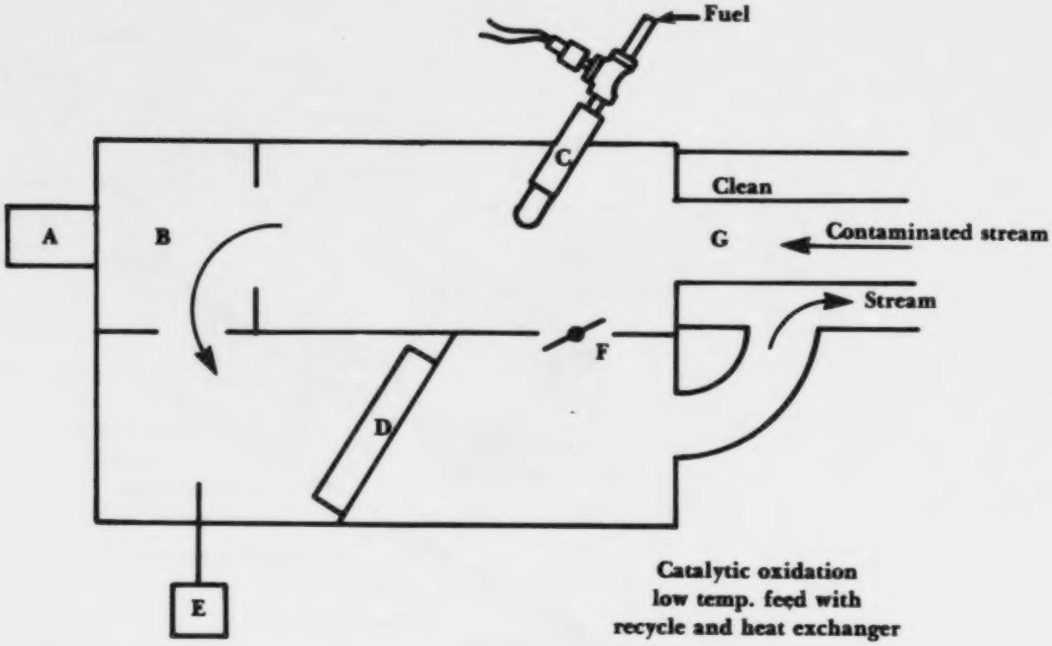
3. Worley, F. L., Motard, R. L., "Control Equipment Design and Analysis (CEDA): Gaseous Pollutants," USEPA Contract No. 68-02-1084, University of Houston Report (January 1976).
4. "Study of Systems for Heat Recovery from Afterburners," USEPA Contract No. 68-02-1473 (Task 23), Industrial Gas Cleaning Institute, Inc. Report (April 1978).
5. "Control of Volatile Organic Emissions from Existing Stationary Sources—Vol. I: Control Methods for Surface-Coating Operation," USEPA Report No. EPA-450/2-76-028 (OAQPS No. 1.2-067) (November 1976).
   Vol. II—EPA-450/2-77-008
   Vol. III—EPA-450/2-77-032
   Vol. IV—EPA-450/2-77-033
   Vol. V—EPA-450/2-77-034

Attachment 13-1. Sectional view of direct-flame afterburner (Gas Processors, Inc., Brea, CA)[1]


Flame sensor
Burner
Sample port
Refractory
Insulation
Turbulent expansion zone
Steel shell
Compression zone
Cooling air
induction system
(adjustable)
RETURN HEAT
Pressure tap
Straightening
vanes
Gas system
control
Control panel
(remote optional)
Unitized mounting
Sample port
Temperature sensor
Blower
Insulation

Note: The turbulent expansion zone promotes mixing, as gases decrease their velocity for proper residence time. The compression zone in this design allows for better control and a modest blower size.

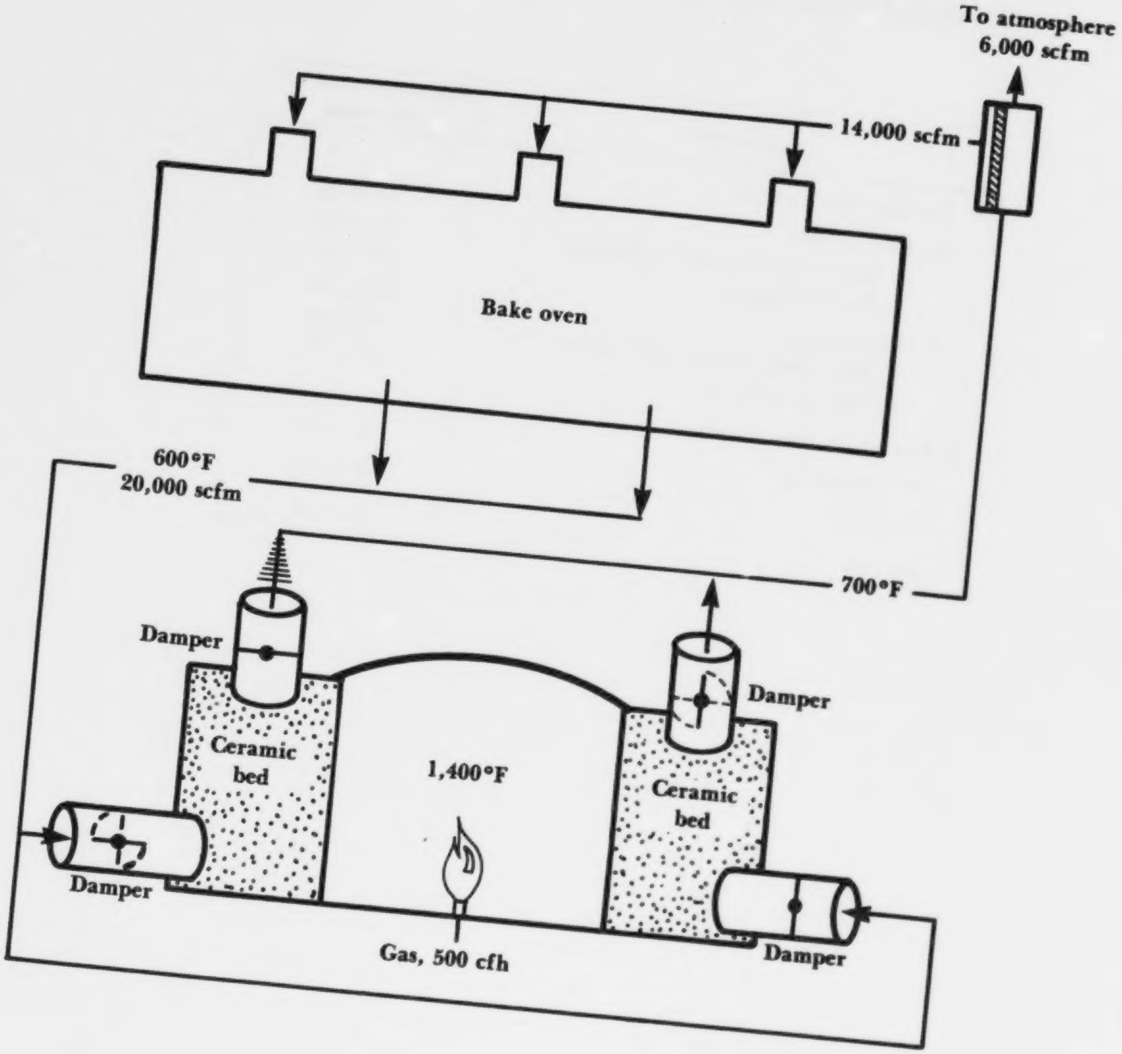
Attachment 13-2. Catalytic incinerator with recycle and heat economizer


Fuel
C
Clean
A
B
G
Contaminated stream
Stream
F
D
E

Catalytic oxidation
low temp. feed with
recycle and heat exchanger

- A. Blower motor
- B. Blower (mixer)
- C. Fuel burner
- D. Catalytic element
- E. Temperature controller
- F. Recycle damper
- G. Heat exchanger

Attachment 13-3. Ceramic bed regenerative-type incineration and heat recovery system


To atmosphere
6,000 scfm
14,000 scfm
Bake oven
600°F
20,000 scfm
700°F
Damper
Damper
Ceramic bed
1,400°F
Ceramic bed
Damper
Damper
Gas, 500 cfh

Attachment 13-4. Reported range of heat recovery per stage by application and type of afterburner equipment[4]

Application	Recovery range, % per stage
1. Gas/gas heat transfer	
A. Recuperative	31 to 78
1. Heat fumes before combusting	31 to 78
2. Heat makeup air	40 to 50
B. Regenerative	43 to 85
1. Heat fumes before combusting	70 to 85
2. Heat makeup air	43 to 75
2. Gas/liquid heat transfer	
A. Economizer	9 to 62
B. Boiler	20 to 80
3. Recycle	70 to 80

Attachment 13-5. Energy savings from afterburner exhausts[4]

System no. (1)	Heat energy[a] discharged to atmosphere from afterburning without heat recovery, 10^6 Btu/yr (2)	Heat energy discharged to atmosphere from afterburning with heat recovery, 10^6 Btu/yr (3)	Heat energy saved from process exhaust, 10^6 Btu/yr (4)	Heat energy saved from process exhaust, % (5)	Purchased electricity to operate heat recovery with afterburner, 10^6 Btu/yr (6)	Net energy savings, 10^6 Btu/yr (7)	Net energy savings, % (8)
1	52,243	12,690	39,553	76	497	39,056	74.7
2	192,920	44,118	148,802	77	4,058	144,744	75.0
3	127,600	16,313	111,287	87	(153)	111,440	87.3
4	38,198	15,177	33,021	86	205	32,816	85.9
5	160,583	37,930	122,653	76	766	127,887	75.9
6	149,463	27,443	122,020	82	411	121,609	81.4
7	180,145	34,100	146,045	81	1,075	144,970	80.5
8	68,120	12,284	55,836	82	4,535	51,299	75.3
9	128,163	25,633	102,530	80	900	101,630	79.3
10	76,184	16,370	59,814	78	497	59,317	77.9

[a] Based on 1400°F incinerating and exhaust

Appendix 13-1
(Partial Exerpt)

EPA-450/2-76-028
(OAQPS No. 1.2-067)

Control of Volatile Organic Emissions from Existing Stationary Sources— Volume I: Control Methods for Surface-Coating Operations

Emission Standards and Engineering Division
Chemical and Petroleum Branch

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

November 1976

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3.2.2 Incineration

3.2.2.1 Introduction – Incineration destroys organic emissions by oxidizing them to carbon dioxide and water vapor. Incineration is the most universally applicable control method for organics; given the proper conditions, any organic compound will oxidize. Oxidation proceeds more rapidly at higher temperatures and higher organic pollutant content. Incinerators (also called afterburners) have been used for many years on a variety of sources ranging in size from less than 1000 scfm to greater than 40,000 scfm.

Use of existing process heaters for incineration – The use of existing boilers and process heaters for destruction of organic emissions provides for the possibility of pollution control at small capital cost and little or no fuel cost. The option is, however, severely limited in its application. Some of the requirements are:

1. The heater must be operated whenever the pollution source is operated. Emissions will be uncontrolled during process heater down time.
2. The fuel rate to the burner cannot be allowed to fall below that required for effective combustion. On-off burner controls are not acceptable.
3. Temperature and residence time in the heater firebox must be sufficient.
4. For proper control, the volume of polluted exhaust gas must be much smaller than the burner air requirement and be located close to the process heater. For most plants doing surface coating, especially if surface coating is their main business, the combustion air requirement is smaller than the coater-related exhaust. In many diversified plants, the coating operation may be distant from heaters and boilers.
5. Constituents of the coating-related exhaust must not damage the internals of the process heater.

Few boilers or heaters meet these conditions.

Use of add-on incinerators – In noncatalytic incinerators (sometimes called thermal or direct flame incinerators), a portion of the polluted gas may be passed through the burner(s) in which auxiliary fuel is fired. Gases exiting the burner(s) in excess of 2000°F are blended with the bypassed gases and held at temperature until reaction is complete. The equilibrium temperature of mixed gases is critical to effective combustion of organic pollutants. A diagram of a typical arrangement is shown in Figure 3-10.

The coupled effect of temperature and residence time is shown in Figure 3-11. Hydrocarbons will first oxidize to water, carbon monoxide and possibly carbon and partially oxidized organics. Complete oxidation converts *CO* and residuals to carbon dioxide and water. Figure 3-12 shows the effect of temperature on organic vapor oxidation and carbon monoxide oxidation.

A temperature of 1100 to 1250°F at a residence time of 0.3 to 0.5 second[2] is sufficient to achieve 90 percent oxidation of most organic vapors, but about 1400 to 1500°F may be necessary to oxidize methane, cellosolve, and substituted aromatics such as toluene and zylene.[2]

Design – Incineration fuel requirements are determined by the concentration of the pollutants, the waste stream temperature and oxygen level, and the incineration temperature required. For most organic solvents, the heat of combustion is

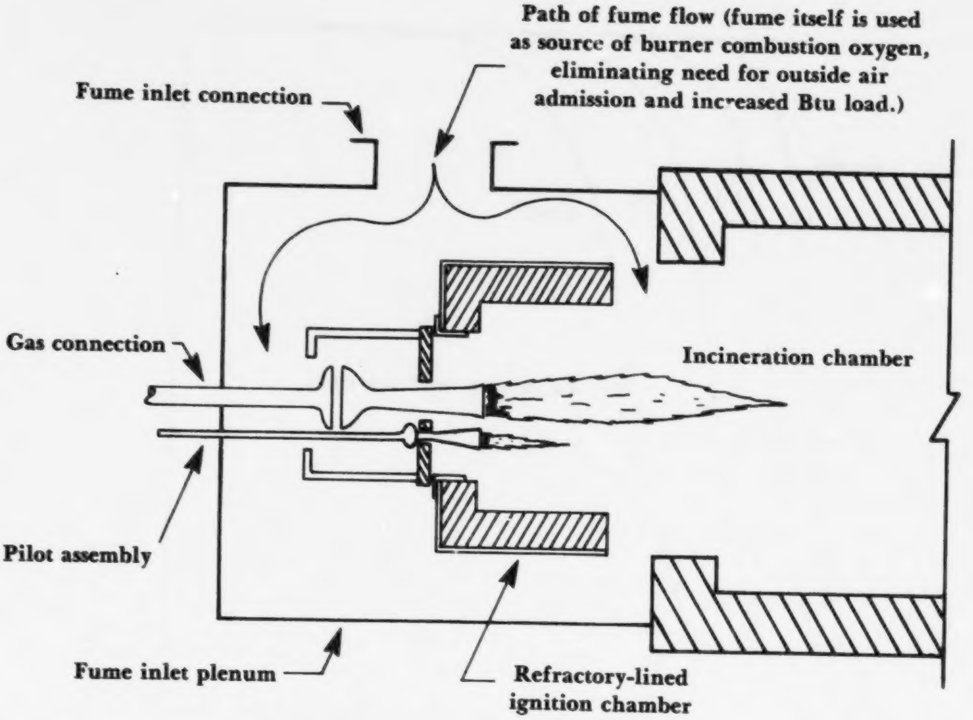
Path of fume flow (fume itself is used as source of burner combustion oxygen, eliminating need for outside air admission and inc*eased Btu load.)
Fume inlet connection
Gas connection
Incineration chamber
Pilot assembly
Fume inlet plenum
Refractory-lined ignition chamber

Figure 3-10. Typical burner and chamber arrangement used in direct-flame incinerator.

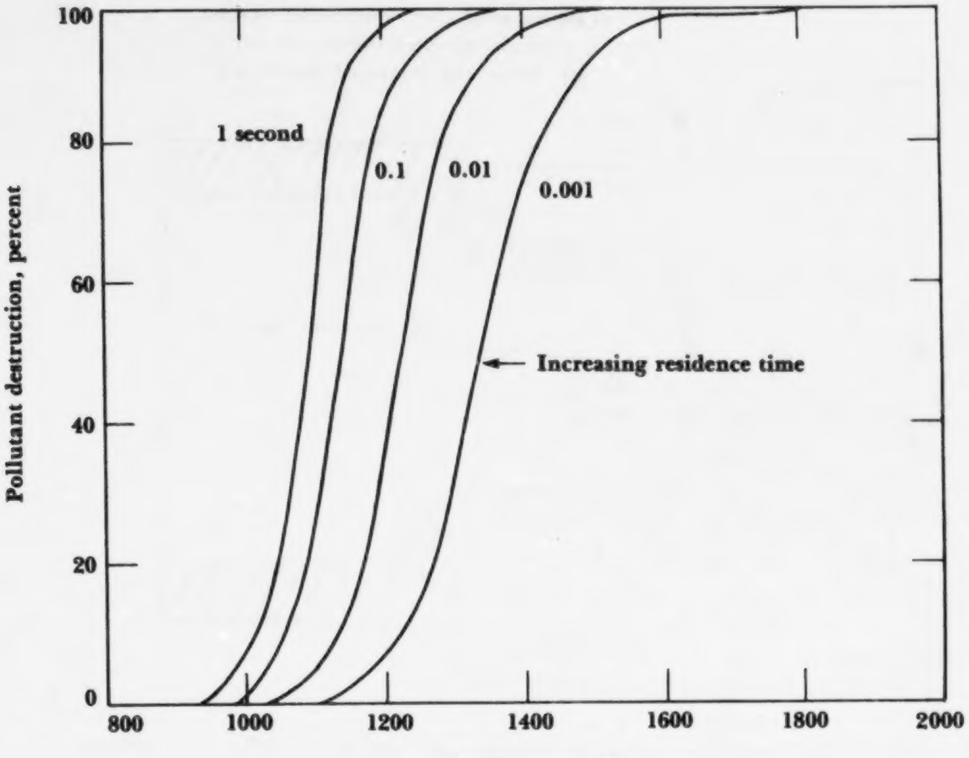

Figure 3-11. Coupled effects of temperature and time on rate of pollutant oxidation.[1]

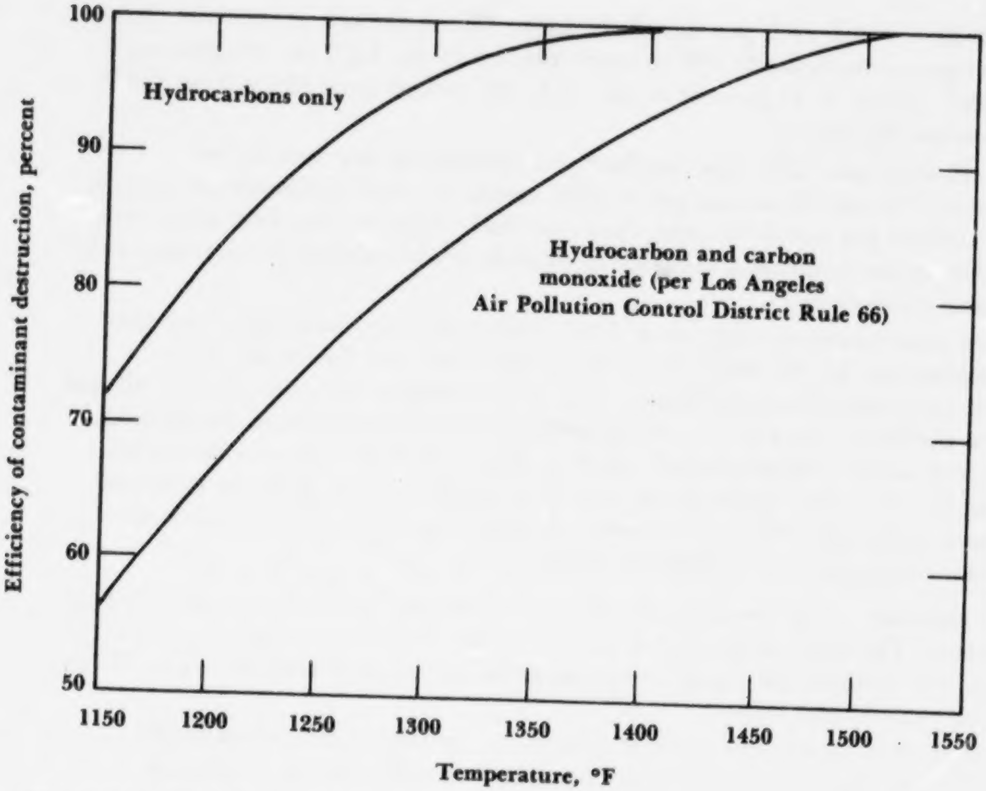

Figure 3-12. Typical effect of operating temperature on effectiveness of thermal afterburner for destruction of hydrocarbons and carbon monoxide.[1]

about 0.5 Btu/scf for each percent of the LEL. This is enough to raise the waste stream temperature about 27.5 °F for each percent of the LEL (at 100 percent combustion). Thus, at 25 percent of the LEL, the temperature rise will be 620 °F for 90 percent conversion.

Fuel—Natural gas, LPG and distillate and residual oil are used to fuel incinerators. The use of natural gas or LPG results in lower maintenance costs; at present, natural gas also is the least expensive fuel. However, the dwindling natural gas supplies make it almost a necessity to provide newly installed incinerators with oil-burning capabilities.

In most cases where natural gas or LPG is not available, incinerators are fixed with distillate fuel oil; residual oil is seldom employed. Oil flames are more luminous and longer than gas flames, thus require longer fireboxes. Almost all fuel oils, even distillate, contain measurable sulfur compounds. Residual oils generally have greater sulfur and particulate contents and many have appreciable nitrogen fractions. Sulfur oxides, particulates and NO_X in combustion products from fuel oil increase pollution emissions and cause corrosion and soot accumulation on incinerator work and heat transfer surfaces.

Heat recovery—Heat recovery offers a way to reduce the energy consumption of incinerators. The simplest method is to use the hot cleaned gases exiting the incinerator to preheat the cooler incoming gases. Design is usually for 35 to 90 percent heat recovery efficiency.

The maximum usable efficiency is determined by the concentration of the organics in the gases, the temperature of the inlet gases, and the maximum temperature that the incinerator and heat exchangers can withstand.

In a noncatalytic system with a primary heat exchanger, the preheat temperature should not exceed 680 °F, at 25 percent LEL, in order to limit incinerator exit temperatures to about 1450 °F for the protection of the heat exchanger. The auxiliary fuel would heat the stream about 150 °F and oxidation of the solvent would heat it about 620 °F for an exit temperature of $680 + 150 + 620 = 1450$ °F. At 12 percent LEL the preheat temperature should not exceed 930 °F. Most burners have not been designed to tolerate temperatures above 1100 °F.

There are several types of heat recovery equipment using different materials at various costs. The most common is the tube and shell heat exchanger. The higher temperature exhaust passes over tubes, which have lower temperature gas or liquid flowing through the tubes; thus increasing the temperature of that gas or liquid. Another method uses a rotating ceramic or metal wheel whose axis is along the wall between two tunnels. Hot exhaust flows through one tunnel and heats half of the wheel. Lower temperature air flows through the other tunnel and is heated as the wheel rotates. Another method uses several chambers containing inert ceramic materials with high heat retention capability. The hot gas (e.g., from the incinerator) passes through these beds and heats the ceramic material. The air flow is then reversed, and lower temperature gas passes through the heated beds; thus raising the temperature of that gas to near incineration temperature. Further details on various heat recovery methods and equipment can be obtained from the vendors of incinerators.

The use of incinerator exhaust to preheat incinerator inlet air is often referred to as "primary" heat recovery as illustrated in Case 2 of Figure 3-13. Since some systems have a maximum allowable inlet temperature for the incinerator, it may not be possible to recover all of the heat available in the incinerator exhaust. In such cases, the inlet to the incinerator is controlled to minimize fuel requirements. Note that a non-catalytic incinerator always requires some fuel to initiate combustion.

"Secondary" heat recovery uses incinerator exhaust from the primary heat recovery stage (or from the incinerator directly if there is no primary heat recovery) to replace energy usage elsewhere in the plant. This energy can be used for process heat requirements or for plant heating. The amount of energy that a plant can recover and use depends on the individual circumstances at the plant. Usually recovery efficiency of 70 to 80 percent is achievable, making the net energy consumption of an incinerator minimal or even negative if gases are near or above 25 percent of the LEL. The use of primary and secondary heat recovery is illustrated in Case 3 of Figure 3-13. It should be noted that heat recovery reduces operating expenses for fuel at the expense of increased capital costs. Primary heat recovery systems are within the incinerator and require no long ducts. Secondary heat recovery may be difficult to install on an existing process because the sites where recovered energy may be used are often distant from the incinerator. In applying calculated values for recovered energy values in Case 3 to real plants, the cost of using recovered energy must be considered. If secondary heat recovery is used, often the plant cannot operate unless the control system is operating because it supplies heat required by the plant.

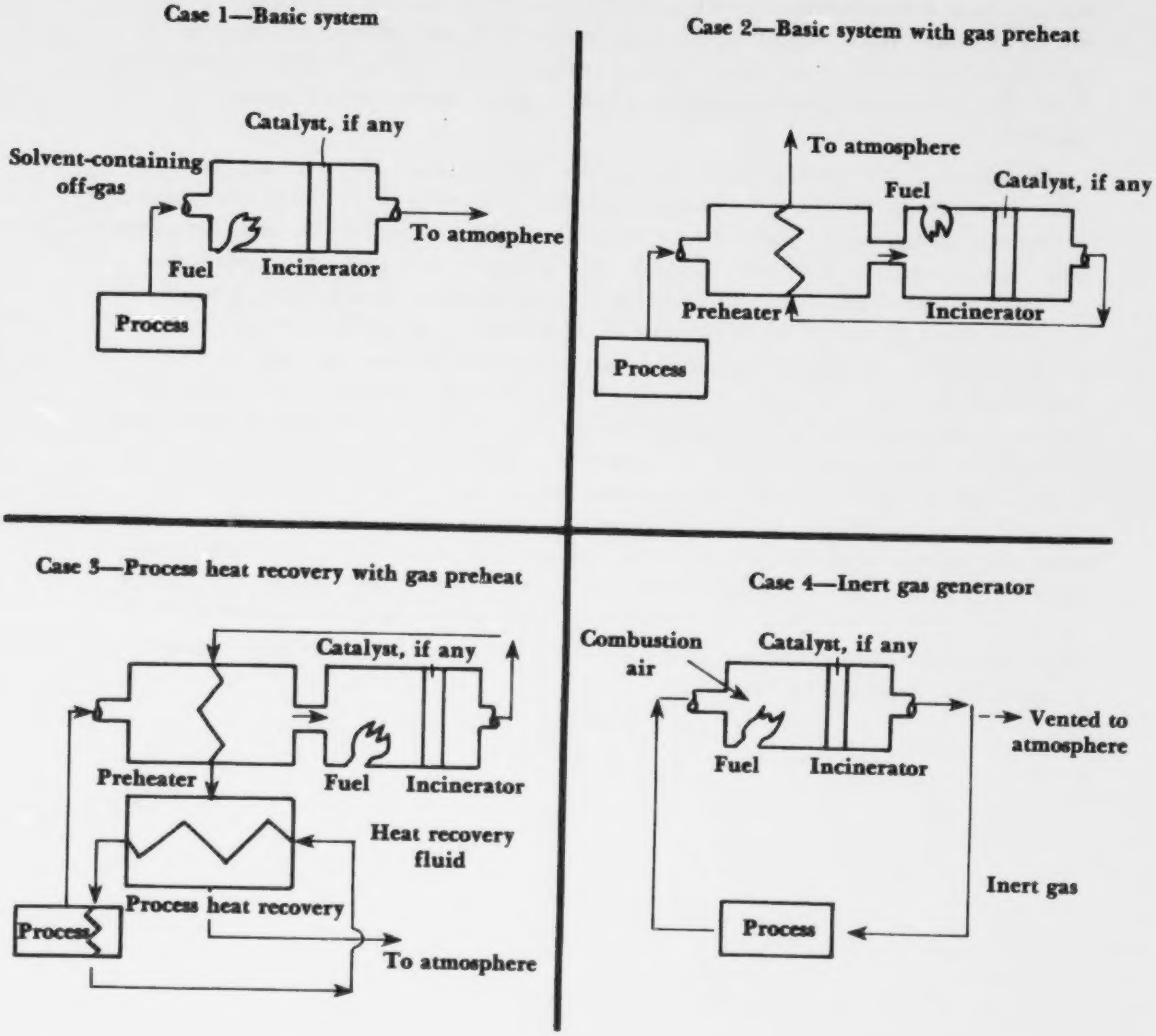
Case 1—Basic system
Catalyst, if any
Solvent-containing off-gas
To atmosphere
Fuel
Incinerator
Process
Case 2—Basic system with gas preheat
To atmosphere
Fuel
Catalyst, if any
Preheater
Incinerator
Process
Case 3—Process heat recovery with gas preheat
Catalyst, if any
Preheater
Fuel
Incinerator
Heat recovery fluid
Process heat recovery
Process
To atmosphere
Case 4—Inert gas generator
Combustion air
Catalyst, if any
Vented to atmosphere
Fuel
Incinerator
Inert gas
Process

Figure 3-13. Configurations for catalytic and noncatalytic incineration.

If the gases in an oven are inert, that is, contain little oxygen, explosions are not possible and high concentrations of organic solvent vapor can be handled safely. The oven exhaust can be blended with air and burned with minimal auxiliary fuel. The incinerator may be the source of inert gas for the oven. Cooling of the incinerator gas is necessary, removing energy that can be used elsewhere. Case 4 of Figure 3-13 illustrates this scheme. A modification of the scheme shown is the use of an external inert gas generator. This scheme can have a significant energy credit because the otherwise discarded organics are converted to useful energy. Because of the specialized nature of Case 4, it may not be applicable to retrofit on existing ovens and costs for this case are not included in this study. Note that in this case the incinerator exhaust is in contact with the product. This limits the available fuel for this option to natural gas or propane. The use of this option would probably be impossible if any compounds containing appreciable sulfur or halogens are used.

To illustrate a specific case, Figure 3-14 outlines a source controlled by a non-catalytic incinerator. The source is assumed to operate 25 percent of the LEL and the incinerator has primary and secondary heat recovery. The primary heat exchanger raises the temperature to 700°F, at 35 percent heat recovery efficiency. The heat of combustion of the organic vapors provides a 620°F additional temperature rise at 90 percent combustion and the burner must supply only enough heat to raise the gases 80°F to reach the design combustion temperature of 1400°F. Combustion products pass through the primary heat exchanger—where they are cooled to 1025°F—and enter a 35 percent efficient secondary heat exchanger. In the secondary heat exchanger, further energy is recovered for use in other areas. In this example, makeup air for the source is heated from ambient temperatures to source entrance temperatures (higher than oven exit temperatures).

The energy implications of this scheme can be seen by comparing the energy input of this controlled source with an uncontrolled source. In an uncontrolled source, fuel would be necessary to raise the temperature of the makeup air from 70°F to 425°F or 355°F. For a controlled source, fuel would only need to raise the temperature 80°F. Thus, the energy input would be reduced by over 80 percent by use of incineration simply because the organic vapors contribute heat when they burn.

In the above analysis, the assumptions made are important. If the organic vapors are more dilute, the temperature rise due to combustion will be less. Heat recovery can be more efficient than 35 percent, making up for all or some of this difference. Finally, the analysis assumes that the heat recovered in the secondary heat exchanger can be used in the plant. The heat can be used to produce steam, heat water, supply process heat or heat buildings. Obviously, a case-by-case analysis is necessary to ascertain how much recovered heat could be used.

Particulates—The level of particulate concentration found in surface coating operations should not pose any problems for noncatalytic volatile organic combustion. However, an incinerator designed for hydrocarbon removal usually will not have sufficient residence time to efficiently combust organic particulates.

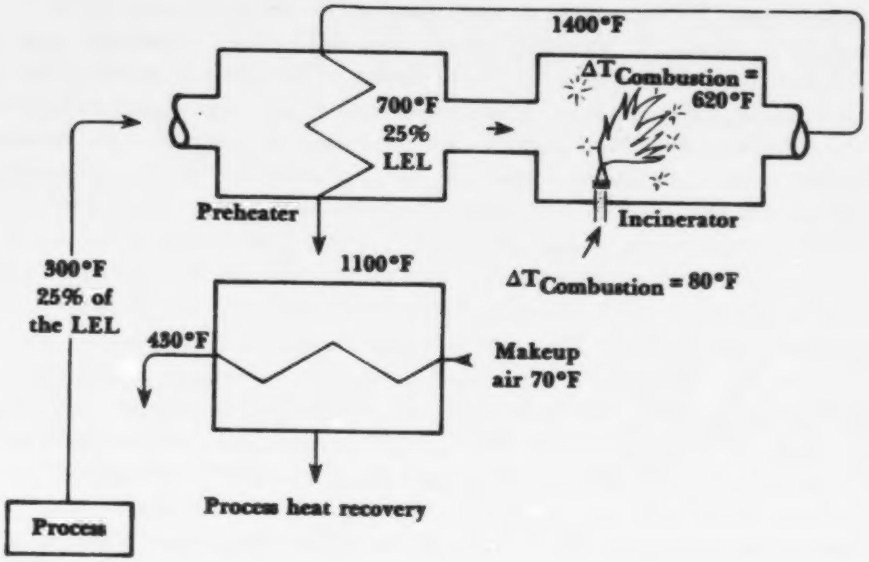
1400°F
ΔT Combustion = 620°F
700°F
25%
LEL
Preheater
Incinerator
ΔT Combustion = 80°F
1100°F
300°F
25% of
the LEL
430°F
Makeup
air 70°F
Process heat recovery
Process

Figure 3-14. Example of incinerator on oven with primary and secondary heat recovery.

Safety of preheat—(At 25 percent of the LEL), oxidation rates at temperatures below 1100°F are slow. Complete oxidation can take several seconds. Because the gases are in the heat exchanger for less than a second preignition should not be a problem using heat recovery if temperatures are below 1000°F to 1100°F.

Some problems have occurred in the past with accumulations of condensed materials or particulates igniting in the heat recovery devices. If this occurs, the accumulations must be periodically removed from the heat transfer surfaces. The user should give careful consideration for his particular set of circumstances to potential safety problems. This is especially true if gases at a high percent of the LEL are preheated.

Adverse environmental effects—Sulfur-containing compounds will be converted to their oxides; halogen-containing compounds will be converted to acids. A portion of nitrogen-containing compounds will be converted to NO_x and additional NO_x will result from thermal fixation. If use of these compounds cannot be avoided, the benefit from incineration should be evaluated against the adverse effects and alternate methods of control should be thoroughly explored.

The concentration of oxides of nitrogen (NO_x) is about 18 to 22 ppm for natural gas-fired noncatalytic incinerators and 40 to 50 ppm for oil-fired noncatalytic incinerators at a temperature of 1500°F, assuming no nitrogen containing compounds are incinerated.

Effect of technical assumptions on cost models—In the cost estimates (Section 4.2.2.1) for noncatalytic incineration, the organic was assumed to be 50 molar percent hexane and 50 molar percent benzene. For noncatalytic incineration, the two important factors are the heat available per unit volume at the LEL and the temperature necessary for combustion. For most solvents, the heat of combustion at the LEL is about 50 Btu/scf.[2] This will vary about ± 20 percent for almost the entire range of solvents used (methanol and ethanol are slightly higher). Thus, there is little variation due to the type of solvent.

The assumed temperature of combustion (1400°F) is sufficient to obtain 95+ percent removal of the entire range of organics used as solvents.

3.2.2.2 Catalytic incineration—A catalyst is a substance that speeds up the rate of chemical reaction at a given temperature without being permanently altered. The use of a catalyst in an incinerator reportedly enables satisfactory oxidation rates at temperatures in the range of 500 to 600°F inlet and 750 to 1000°F outlet. If heat recovery is not practiced, significant energy savings are possible by use of a catalyst. The fuel savings become less as primary and secondary heat recovery are added. Because of lower temperatures, materials of construction savings are possible for heat recovery and for the incinerator itself. A schematic of one possible configuration is shown in Figure 3-15.

Catalysts are specific in the types of reactions they promote. There are, however, oxidation catalysts available that will work on a wide range of organic solvents. The effect of temperature on conversion for solvent hydrocarbons is shown in Figure 3-16. Common catalysts are platinum or other metals on alumina pellet support or on a honeycomb support. All-metal catalysts can also be used.

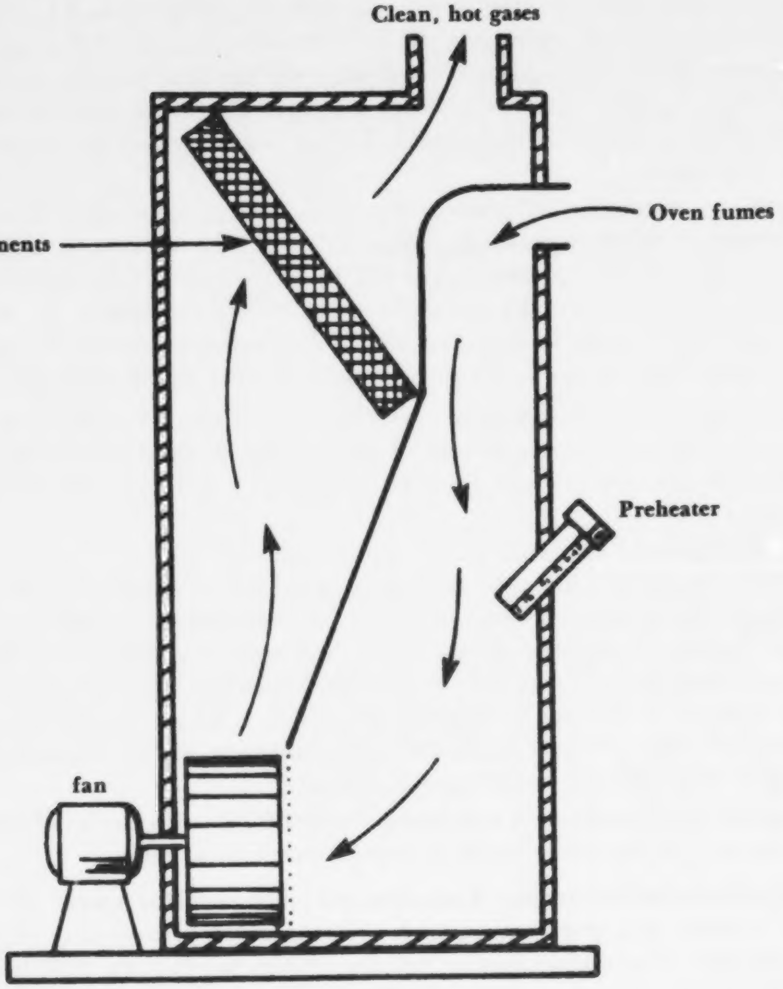
Clean, hot gases
Oven fumes
Catalyst elements
Preheater
fan

Figure 3-15. Schematic diagram of catalytic afterburner using torch-type preheat burner with flow of preheater waste stream through fan to promote mixing.[1]

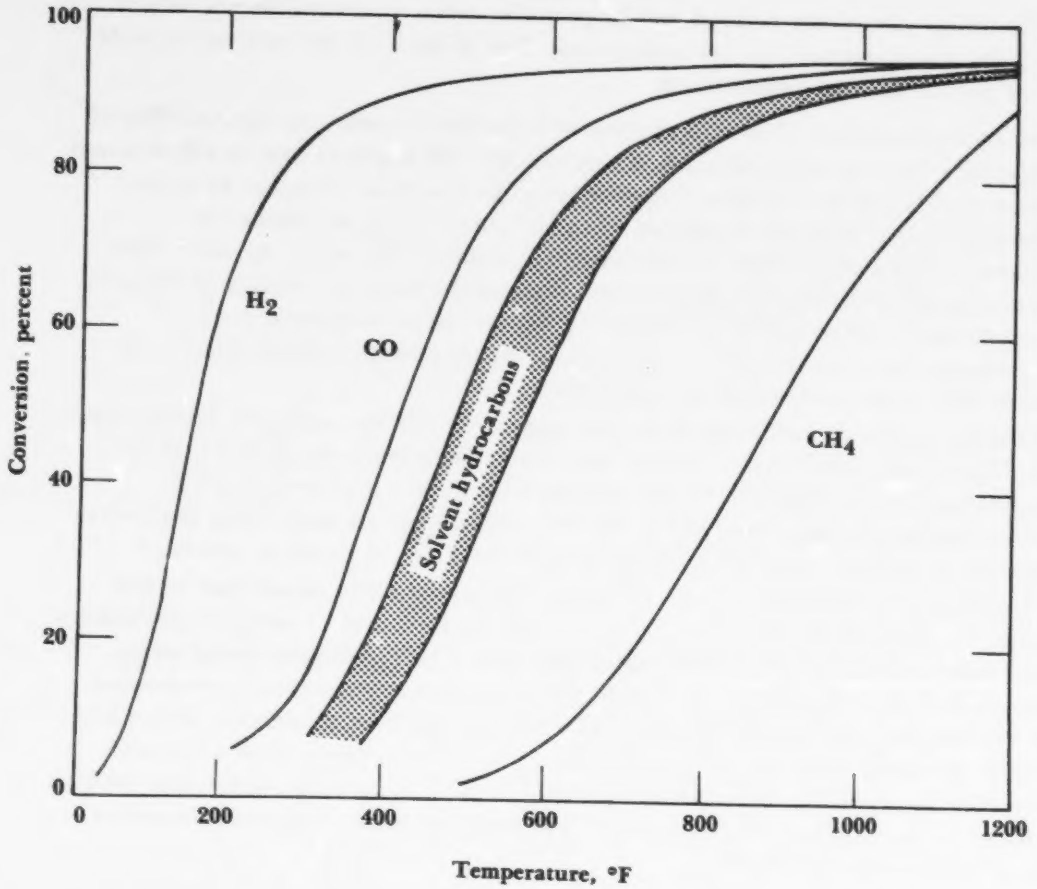

Figure 3-16. Effect of temperature on conversion for catalytic incineration.[1]

The initial cost of the catalyst and its periodic replacement represents, respectively, increased capital and operating costs. The lifetime of the catalyst depends on the rate of catalyst deactivation.

Catalyst deactivation—The effectiveness of a catalyst requires the accessability of "active sites" to reacting molecules. Every catalyst will begin to lose its effectiveness as soon as it is put into service. Compensation for this must be made by either overdesigning the amount of catalyst in the original charge or raising the temperature into the catalyst to maintain the required efficiency. At some time, however, activity decays to a point where the catalyst must be cleaned or replaced. Catalysts can be deactivated by normal aging, by use at excessively high temperature, by coating with particulates, or by poisoning. Catalyst lifetime of greater than 1 year is considered acceptable.

Catalyst material can be lost from the support by erosion, attrition, or vaporization. These processes increase with temperature. For metals on alumina, if the temperature is less than 1100°F, life will be 3 to 5 years if no deactivation mechanisms are present. At 1250 to 1300°F, this drops to 1 year. Even short-term exposure to 1400 to 1500°F can result in near total loss of catalytic activity.[1]

The limited temperature range allowable for catalysts sets constraints on the system. As mentioned earlier, at 25 percent of the LEL and 90 percent combustion there will be about a 620°F temperature rise as a result of organic combustion. Because an inlet temperature of 500 to 600°F is necessary to initiate combustion, the catalyst bed exit temperature will be 1120 to 1220°F at 25 percent of the LEL. This is the upper limit for good catalyst life and thus concentrations of greater than 25 percent of the LEL cannot be incinerated in a catalytic incinerator without damage to the catalyst. Restrictions on heat recovery options are also mandated. These will be discussed later.

Coating with particulates—The buildup of condensed polymerized material or solid particulate can inhibit contact between the active sites of the catalyst and the gases to be controlled. Cleaning is the usual method for reactivation. Cleaning methods vary with the catalyst and instructions are usually given by the manufacturer.

Poisoning—Certain contaminants will chemically react or alloy with common catalysts and cause deactivation. A common list includes phosphorus, bismuth, arsenic, antimony, mercury, lead, zinc, and tin. The first five are considered fast acting; the last three are slow acting, especially below 1100°F. Areas of care include avoiding the use of phosphate metal cleaning compounds and galvanized ductwork. Sulfur and halogens are also considered catalyst poisons, but their effect is reversible.

Fuel—Natural gas is the preferred fuel for catalytic incinerators because of its cleanliness. If properly designed and operated, a catalytic incinerator could possibly use distillate oil. However, much of the sulfur in the oil would probably be oxidized to SO_3 which would subsequently form sulfuric acid mist. This would necessitate corrosive resistant materials and would cause the emission of a very undesirable pollutant. Therefore, the use of fuel oil (even low sulfur) in a catalytic incinerator is not recommended.

Heat recovery – The amount of heat that can be transferred to the cooler gases is limited. The usual design is to have the exit temperature from the catalyst bed at about 1000 °F. If the gas is at 15 percent of the LEL, for example, the temperature rise across the bed would be about 375 °F, and the gas could only be preheated to about 625 °F. Secondary heat recovery is limited by the ability to use the recovered energy. If a gas stream is already at combustion temperature, it is not useful to use "primary" heat recovery but "secondary" heat recovery may still be possible. Note that for catalytic incineration, no flame initiation is necessary and thus it is possible to have no fuel input.

As in noncatalytic systems, heat recovery equipment may need periodic cleaning if certain streams are to be processed. For a discussion of the safety of preheat, see Section 3.2.2.2.

Adverse environmental effects of catalytic incineration – As in non-catalytic incineration, if sulfur- or nitrogen-containing compounds are present, their oxides will be generated. If halogenated compounds are present, their acids will be formed. If it is impossible to avoid using these compounds in quantity, incineration may be unwise.

The concentration of NO_x from catalytic incinerators is low, about 15 parts per million,[2] assuming no nitrogen compounds are incinerated.

Effect of technical assumptions on cost models – In the cost estimates for catalytic incineration, the solvent was assumed to be 50 molar percent hexane and 50 molar percent benzene. For catalytic incineration, the two important factors are the heat available per unit volume at the LEL and the temperature necessary for catalytic oxidation.

As discussed earlier, there is little variation in the available heat from combustion at the LEL.

The assumed temperature into the catalytic incinerator is sufficient to obtain 95 percent removal of the entire range of organics used in solvents.

3.4 REFERENCES

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2. Rolke, R. W. et al. Afterburner Systems Study, Shell Development Company, Emeryville, CA, prepared for U.S. Environmental Protection Agency, Research Triangle Park, NC under contract no. ESHD 71-3. Publication no. EPA-R2-72-062. (August 1972).

Chapter 14

Waste-Gas Flares

The material presented in this chapter is an edited version of the work of D. I. Walters and H. B. Couglin, published in *Air Pollution Engineering Manual,* EPA Publication AP-40, second edition, Chapter 10 (May 1973).

Introduction

Large volumes of hydrocarbon gases are produced in modern refinery and petrochemical plants. Generally, these gases are used as fuel or as raw material for further processing. In the past, however, large quantitites of these gases were considered waste gases, and along with waste liquids, were dumped to open pits and burned, producing large volumes of black smoke. With modernization of processing units, this method of waste-gas disposal, even for emergency gas releases, has become less acceptable to the industry. Local and state governments have adopted ordinances (some of which were part of the State Implementation Plans for air pollution control in the early 1970s) limiting the opacity of smoke to 20% or less.

Nevertheless, petroleum refineries are still faced with the problem of safe disposal of volatile liquids and gases resulting from scheduled shut-downs and sudden or unexpected upsets in process units. Emergencies that can cause the sudden venting of excessive amounts of gases and vapors include fires, compressor failures, overpressures in process vessels, line breaks, leaks, and power failures. Uncontrolled releases of large volumes of gases also constitute a serious safety hazard to personnel and equipment.

A system for disposal of emergency and waste refinery gases consists of a manifolded pressure-relieving or blowdown system, and a blowdown recovery system or a system of flares for the combustion of the excess gases, or both. Many refineries, however, do not operate blowdown recovery systems. In addition to disposing of emergency and excess gas flows, these systems are used in the evacuation of units during shutdowns and turnarounds. Normally a unit is shut down by depressuring into a fuel gas or vapor recovery system with further depressuring to essentially atmospheric pressure, by venting to a low-pressure flare system.

A blowdown or pressure-relieving system consists of relief and safety valves, manual bypass valves, blowdown headers, knockout vessels, and holding tanks. A blowdown recovery system also includes compressors and vapor surge vessels, such as gas holders or vapor spheres. This equipment must be designed to permit safe disposal of excess gases and liquids in case operational difficulties or fires occur. These materials are usually removed from the process area by automatic safety and relief valves, as well as by manually controlled valves, manifolded to a header that conducts the material away from the unit involved. The preferred method to dispose of the waste gases, which cannot be recovered in a blowdown recovery system, is by burning them in a smokeless flare. Liquid blowdowns are usually conducted to appropriately designed holding vessels and reclaimed.

A pressure-relieving system used in one modern petroleum refinery is shown in Attachment 14-1. The system is used not only as a safety measure, but also as a means of reducing the emission of hydrocarbons to the atmosphere. This installation actually includes four separate collecting systems, as follows: (a) the low-pressure blowdown system for vapors from equipment with working pressure below 100 psig, (b) the high-pressure blowdown system for vapors from equipment with working pressures above 100 psig, (c) the liquid blowdown system for liquids at all pressures, and (d) the light-ends blowdown for butanes and lighter hydrocarbon blowdown products.

The liquid portion of light hydrocarbon products released through the light-ends blowdown system is recovered in a drum near the flare. A backpressure of 50 psig is maintained on the drum, which minimizes the amount of vapor that vents through a backpressure regulator to the high-pressure blowdown line. The high-pressure, low-pressure, and liquid-blowdown systems all discharge into the main blowdown vesel. Any entrained liquid is dropped out and pumped to a storage tank for recovery. Offgas from this blowdown drum flows to a vertical vessel with baffle trays in which the gases are in direct contact with water, which condenses some of the hydrocarbons and permits their recovery. The overhead vapors from this so-called sump tank flow to the flare system manifold for disposal by burning in a smokeless flare system.

The Air Pollution Problem

The air pollution problem associated with the uncontrolled disposal of waste gases is the venting of large volumes of hydrocarbons and other ordorous gases and aerosols. The preferred control method for excess gases and vapors is to recover them in a blowdown recovery system and, failing that, to incinerate them in an elevated-type flare. Such flares introduce the possibility of smoke and other objectionable gases such as carbon monoxide, sulfur dioxide, and nitrogen oxides. Flares have been further developed to ensure that this combustion is smokeless and, in some cases, nonluminous. Luminosity, while not an air pollution problem, does attract attention to the refinery operation and in certain cases can cause bad public relations. Noise also can result in a nuisance problem if the refinery is located in an area zoned for residential expansion into the property surrounding the plant or if a new facility is built close to a residential area.

Smoke from Flares

The natural tendency of most combustible gases is to smoke when flared. While smoke is the result of incomplete combustion, the important parameter is the H/C ratio of the gas. Gases with an H/C ratio of less than 0.28 will smoke when flared unless steam or water is injected into the flare zone. Further discussion of the importance of the H/C ratio is found in Mandell's paper, Appendix 14-1.

Types of Flares

There are, in general, three types of flares for the disposal of waste gases: elevated flares, ground-level flares, and burning pits.

The burning pits are reserved for extremely large gas flows caused by catastrophic emergencies in which the capacity of the primary smokeless flares is exceeded. Ordinarily, the main gas header to the flare system has a water seal bypass to a burning pit. Excessive pressure in the header blows the water seal and permits the vapors and gases to vent a burning pit where combustion occurs.

The essential parts of a flare are the: burner, stack seal, liquid trap, controls, pilot burner, and ignition system. In some cases, vented gases flow through chemical solutions to receive treatment before combustion. As an example, gases vented from an isomerization unit that may contain small amounts of hydroflouric acid are scrubbed with caustic before venting to the flare.

Elevated Flares

Smokeless combustion can be obtained in an elevated flare by the injection of an inert gas to the combustion zone to provide turbulence and inspirate air. A mechanical air-mixing system would be ideal but is not economical in view of the large volume of gases handled. The most commonly encountered air-inspirating material for an elevated flare is steam.

Attachment 14-3 shows a recent modification of the multiple-nozzle type tip. Modern refining process units with large capacities and greater use of high operating pressures have increased the mass-flow rates to flares, thus requiring larger diameter tips. To ensure satisfactory operation under varied flow conditions, internal injector tubes along with a center tube have been added. The injector tubes provide additional turbulence and combustion air, while the central steam jet and attached diffuser plate provide additional steam to eliminate smoke at low flow conditions. The flare continues to employ steam jets placed concentrically around the tip, as shown in Attachment 14-2, but in a modified form. Noise problems may result at the injector tubes if muffling devices are not used.

A second type of elevated flare has a flare tip with no obstruction to flow, that is, the flare tip is the same diameter as the stack. The steam is injected by a single nozzle located concentrically within the burner tip. In this type of flare, the steam is premixed with the gas before ignition and discharge.

A third type of elevated flare has been used by the Sinclair Oil Company (4). It is equipped with a flare tip constructed to cause the gases to flow through several tangential openings to promote turbulence. A steam ring at the top of the stack has numerous equally spaced holes about 1/8-inch in diameter for discharging steam into the gas stream.

The injection of steam in this latter flare may be automatically or manually controlled. In most cases, the steam is proportioned automatically to the rate of gas flow; however, in some installations, the steam is automatically supplied at maximum rates, and manual throttling of a steam valve is required for adjusting the steam flow to the particular gas flow rate. There are many variations of instrumentation among various flares, some designs being more desirable than others. For economic reasons, all designs attempt to proportion steam flow to the gas flow rate.

Steam injection is generally believed to result in the following benefits: (a) energy available at relatively low cost can be used to inspirate air and provide turbulence within the flame, (b) steam reacts with the fuel to form oxygenated compounds that burn readily at relatively low temperatures, (c) water-gas reactions also occur with this same end result, and (d) steam reduces the partial pressure of the fuel and retards polymerization. (Inert gases such as nitrogen have also been found effective for this purpose; however, the expense of providing such a diluent is prohibitive.)

Multistream-Jet-Type Elevated Flare

A multistream-jet-type elevated flare (3) is shown in Attachment 14-4. All relief headers from process units combine to a common header that conducts the hydrocarbon gases and vapors to a large knockout drum. Any entrained liquid is dropped out and pumped to storage. The gases then flow in one of two ways. For emergency gas releases that are smaller than or equal to the design rate, the flow is directed to the main flare stack. Hydrocarbons are ignited by continuous pilot burners, and steam is injected by means of small jet fingers placed concentrically about the stack tip. The steam is injected in proportion to the gas flow. The steam control system consists of a pressure controller, having a range of 0 to 20 inches water column, that senses the pressure in the vent line and sends an air signal to a valve operator mounted on a 2-inch V-port control valve in the steam line. If the emergency gas flow exceeds the designed capacity of the main flare, backpressure in the vent lines increases, displacing the water seal, and permitting gas flow to the auxiliary flare. Steam consumption of the burner at a peak flow is about 0.2 to 0.5 pound of steam per pound of gas, depending upon the amount and composition of hydrocarbon gases being vented. In general, the amount of steam required increases with increased molecular weight and the degree of and the degree of unsaturation of the gas.

A small amount of steam (300 to 400 pounds per hour) is allowed to flow through the jet fingers at all times. This steam not only permits smokeless combustion of gas flows too small to actuate the steam control valves but also keeps the jet fingers cooled and open.

Esso-Type Elevated Flare

A second type of elevated, smokeless, steam-injected flare is the Esso type. The design is based upon the original installation in the Bayway Refinery of the Standard Oil Company of New Jersey (7 and 8). A typical flare system serving a petrochemical plant using this type burner is shown in Attachment 14-5. The type of hydrocarbon gases vented can range from a saturated to a completely unsaturated material. The injection of steam is not only proportioned by the pressure in the blowdown lines but is also regulated according to the type of material being flared. This is accomplished by the use of a ratio relay that is manually controlled. The relay is located in a central control room where the operator has an unobstructed view of the flare tip. In normal operation the relay is set to handle feed gas, which is most common to this installation.

In this installation, a blowdown header conducts the gases to a water seal drum as shown in Attachment 14-6. The end of the blowdown line is equipped with two slotted orifices. The flow transmitter senses the pressure differential across the seal drum and transmits an air signal to the ratio relay. The signal to this relay is either amplified or attenuated, depending upon its setting. An air signal is then transmitted to a flow controller that operates two parallel steam valves. The 1-inch steam valve begins to open at an air pressure of 3 psig and is fully open at 5 psig. The 3-inch valve starts to open at 5 psig and is fully open at 15 psig air pressure. As the gas flow increases, the water level in the pipe becomes lower than the water level in the drum, and more of the slot is uncovered. Thus, the difference in pressure between the line and the seal drum increases. This information is transmitted as an air signal to actuate the steam valves. The slotted orifice senses flows that are too small to be indicated by a Pitot-tube-type flow meter. The water level is maintained 1½ inches above the top of the orifice to take care of sudden surges of gas to the system.

A 3-inch steam nozzle is so positioned within the stack that the expansion of the steam just fills the stack and mixes with the gas to provide smokeless combustion. This type of flare is probably less efficient in the use of steam than some of the commercially available flares, but it is desirable from the standpoints of simpler construction and lower maintenance costs.

Sinclair-Type Elevated Flare

A diagram (4) of an installation using a Sinclair-type elevated flare is shown in Attachment 14-7. Details of the burner design are shown in Attachment 14-8.

The flow of steam from the ring inspirates air into the combustion area, and the shroud protects the burner from wind currents and provides a partial mixing chamber for the air and gas. Steam is automatically supplied when there is gas flow. A pressure-sensing element actuates a control valve in the steam supply line. A small bypass valve permits a small, continuous flow of steam to the ring, keeping the ring holes open and permitting smokeless burning of small gas flows.

Ground-Level Flares

There are four principal types of ground-level flare: horizontal venturi, water injection, multi-jet, and vertical venturi.

Horizontal, Venturi-type Ground Flare

A typical horizontal, venturi-type ground flare system is shown in Attachment 14-9. In this system, the refinery flare header discharges to a knockout drum where any entrained liquid is separated and pumped to storage. The gas flows to the burner header, which is connected to three separate banks of standard gas burners through automatic valves of the snap-action type that open at predetermined pressures. If any or all of the pressure valves fail, a bypass line with a liquid seal is provided (with no valves in the circuit), which discharges to the largest bank of burners.

The automatic-valve operation schedule is determined by the quantity of gas most likely to be relieved to the system. The allowable back-pressure in the refinery flare header determines the minimum pressure for the control valve on the No. 1 burner bank. On the assumption that the first valve was set at 3 psig, then the second valve for the No. 2 burner bank would be set for some higher pressure, say 5 psig. The quantity of gas most likely to be released then determines the size and the number of burners for this section. Again, the third most likely quantity of gas determines the pressure setting and the size of the third control valve. Together, the burner capacity should equal the maximum expected flow rate.

A small flare unit of this design, with a capacity of 2 million scf per day, reportedly cost approximately $5,000 in 1953 (2). Another large, horizontal, venturi-type flare that has a capacity of 14 million scfh and requires specially constructed venturi burners (throat diameter ranges from 5 to 18 inches), reportedly cost about $63,000.

Water Injection-Type Ground Flare

Another type of ground flare used in petroleum refineries has a water spray to inspirate air and provide water vapor for the smokeless combustion of gases (Attachment 14-10). This flare requires an adequate supply of water and a reasonable amount of open space.

The structure of the flare consists of three concentric stacks. The combustion chamber contains the burner, the pilot burner, the end of the ignitor tube, and the water spray distributor ring. The primary purpose of the intermediate stack is to confine the water spray so that it will be mixed intimately with burning gases. The outer stack confines the flame and directs it upward.

Water sprays in elevated flares are not too practical for several reasons. It is difficult to keep the water spray in the flame zone, and scale formed in the waterline tends to plug the nozzles. In one case it was necessary to install a return system that permitted continuous waterflow to bypass the spray nozzle. Water main pressure dictates the height to which water can be injected without the use of a booster pump. For a 100- to 250-foot stack, a booster pump would undoubtedly be required. Rain created by the spray from the flare stack is objectionable from the standpoint of corrosion of nearby structures and other equipment.

Water is not as effective as steam for controlling smoke with high gas flow rates, unsaturated materials, or wet gases. The water spray flare is economical when venting rates are not too high and slight smoking can be tolerated. In Los Angeles County, where restrictions on the emission of smoke from flares are very strict, a water spray smokeless flare is not acceptable.

Multijet-Type Ground Flare

A recent type of flare developed by the refining industry is known as multijet (6). This type of flare was designed to burn excess hydrocarbons without smoke, noise, or visible flame. It is claimed to be less expensive than the steam-injected type, on the assumption that new steam facilities must be installed to serve a steam-injected flare unit. Where the steam can be diverted from noncritical operations such as tank heating, the cost of the multijet flare and the steam-inspirating elevated flare may be similar.

A sketch of an installation of a multijet flare is shown in Attachment 14-11. The flare uses two sets of burners; the smaller group handles normal gas leakage and small gas releases, while both burner groups are used at higher flaring rates. This sequential operation is controlled by two water-sealed drums set to release at different pressures. In extreme emergencies, the multijet burners are bypassed by means of a water seal that directs the gases to the center of the stack. This seal blows at flaring rates higher than the design capacity of the flare. At such an excessive rate, the combustion is both luminous and smoky, but the unit is usually sized so that an overcapacity flow would be a rare occurrence. The overcapacity line may also be designed to discharge through a water seal to a nearby elevated flare rather than to the center of a multijet stack.

Vertical, Venturi-Type Ground Flare

Another type of flare based upon the use of commercial-type venturi burners is shown in Attachment 14-12. This type of flare has been used to handle vapors from gas-blanketed tanks, and vapors displaced from the depressuring of butane and propane tank trucks. Since the commercial venturi burner requires a certain minimum pressure to operate efficiently, a gas blower must be provided. Some installations provide two burners which operate at a pressure of ½ to 8 psig. A compressor takes vapors from storage and discharges them at a rate of 6,000 cfh and 7 psig through a water seal tank and a flame arrestor to the flare. This type of arrangement can readily be modified to handle different volumes of vapors by installing the necessary number of burners.

This type of flare is suitable for relatively small flows of gas of a constant rate. Its main application is in situations where other means of disposing of gases and vapors are not available.

Effect of Steam Injection

A flare installation that does not inspirate an adequate amount of air, or does not mix the air and hydrocarbons properly, emits dense, black clouds of smoke that obscure the flame. The injection of steam into the zone of combustion causes a gradual decrease in the amount of smoke, and the flame becomes more visible. When trailing smoke has been eliminated, the flame is very luminous and orange with a few wisps of black smoke around the periphery. The minimum amount of steam required produces a yellowish-orange, luminous flame with no smoke. Increasing the amount of steam injection further decreases the luminosity of the flame. As the steam rate increases, the flame becomes colorless and finally invisible during the day. At night this flame appears blue.

An injection of an excessive amount of steam causes the flame to disappear completely and be replaced with a steam plume. An excessive amount of steam may extinguish the burning gases and permit unburned hydrocarbons to discharge to the atmosphere. When the flame is out, there is a change in the sound of the flare because a steam hiss replaces the roar of combustion. The commercially available pilot burners are usually not extinguished by excessive amounts of steam, and the flame reappears as the steam injection rate is reduced. As the use of automatic instrumentation becomes more prevalent in flare installations, the use of excessive amounts of steam and the emission of unburned hydrocarbons decrease and greater steam economies can be achieved. In evaluating flare installations from an air pollution standpoint, controlling the volume of steam is important. Too little steam results in black smoke, which, obviously, is objectionable. Conversely, excessive use of steam produces a white steam plume and an invisible emission of unburned hydrocarbons.

Design of a Smokeless Flare

The choice of a flare is dictated by the particular requirements of the installation. A flare may be located either at ground level or on an elevated structure. Ground flares are less expensive, but locations must be based upon considerations such as proximity of combustible materials, tanks, and refinery processing equipment. In a congested refinery area, there may be no choice but to use an elevated flare.

The usual flare system includes gas collection equipment, the liquid knockout tank preceding the flare stack. A water seal tank is usually located between the knockout pot and the flare stack to prevent flashbacks into the system. Flame arrestors are sometimes used in place of or in conjunction with a water seal pot. Pressure-temperature-actuated check valves have been used in small ground flares to prevent flashback. The flare stack should be continuously purged with steam, refinery gas, or inert gas to prevent the formation of a combustible mixture that could cause an explosion in the stack (5). The purge gas should not fall below its dew point under any condition of flare operation.

To prevent air from entering a flare stack which is used to dispose of gases that are lighter than air, a device known as a molecular seal (John Zink Company) is sometimes used in conjunction with purge gas. It is installed within the flare stack immediately below the flare tip and acts as a gas trap by preventing the lighter-than-air gas from bleeding out of the system and being displaced with air. A cross-section of a flare stack and seal is shown in Attachment 14-13.

The preferred method of inspirating air is to inject steam either into the stack or into the combustion zone. Where there is an abundant supply, water has sometimes been used in ground flares. There is, however, less assurance of complete combustion when water is used, because the flare is limited in its operation by the type and composition of gases it can handle efficiently.

The diameter of the flare stack depends upon the expected emergency gas flow rate and the permissible backpressure in the vapor relief manifold system. The stack diameter is usually the same or greater than that of the vapor header discharging to the stack, and should be the same diameter as, or greater than, that of the burner section. The velocity of the gas in the stack should be as high as possible to permit use of lower stack heights, promote turbulent flow with resultant improved combustion, and prevent flashback. Stack gas velocity is limited to about 500 fps in order to prevent extinction of the flame by blowout. A discharge velocity of 300 to 400 fps, based upon pressure drop considerations, is the optimum design figure for a patented flare tip manufactured by the John Zink Company. The nature of the gas determines optimum discharge velocity.

Three burner designs for elevated flares have been discussed—the multisteam-jet, or Zink, and the Esso and Sinclair types. The choice of burner is a matter of personal preference. The Zink burner provides more efficient use of steam, which is important in a flare that is in constant use. On the other hand, the simplicity, ease of maintenance, and large capacity of the Esso burner might be important considerations in another installation.

As previously mentioned, the amount of steam required for smokeless combustion varies according to the maximum expected gas flow, the molecular weight, and the percent of unsaturated hydrocarbons in the gas. Data for steam requirements for elevated flares are shown in Attachment 14-4. Actual tests should be run on the various materials to be flared in order to determine a suitable steam-to-hydrocarbon ratio. In the typical refinery, the ratio of steam to hydrocarbon varies from 0.2 to 0.5 pounds of steam per pound of hydrocarbon. The John Zink Company's recommendation for their burner is 5 to 6 pounds per 1,000 cubic feet of a 30-molecular-weight gas at a pressure drop of 0.65 psig.

Pilot Ignition System

The ignition of flare gases is normally accomplished with one of three pilot burners. A separate system must be provided for the ignition of the pilot burner to safeguard against flame failure. In this system, an easily ignited flame with stable combustion and low fuel usage must be provided. In addition, the system must be protected from the weather. To obtain the proper fuel-air-ratio for ignition in this system, the two plug valves are opened and adjustments are made with the globe valves, or pressure regulator valves. After the mixing, the fuel-air mixture is lit in an ignition chamber by an automotive spark plug, controlled by a momentary-contact switch. The ignition chamber is equipped with a heavy Pyrex glass window through which both the spark and ignition flame can be observed. The flame front travels through the ignitor pipe to the top of the pilot burner. The mixing of fuel gas and air in the supply lines is prevented by the use of double check valves in both the fuel and air line. The collection of water in the ignitor tube can be prevented by the installation of an automatic drain in the lower end of the tube at the base of the flare. After the pilot burner has been lit, the flame from generator is turned off by closing the plug cocks in the fuel and air lines. This prevents the collection of condensate and the overheating of the ignitor tube.

On elevated flares, the pilot flame is usually not visible, and an alarm system to indicate flame failure is desirable. This is usually accomplished by installing thermocouples in the pilot burner flame. In the event of flame failure, the temperature drops to a preset level, and an alarm sounds.

Instrumentation and Control of Steam and Gas

For adequate prevention of smoke emission and possible violations of air pollution regulations, an elevated, smokeless flare should be equipped to provide steam automatically and in proportion to the emergency gas flow.

Basically, the instrumentation required for a flare is a flow-sensing element, such as a Pitot tube, and a flow transmitter that sends a signal (usually pneumatic) to a control valve in the steam line. Although the Pitot tube has been used extensively in flare systems, it is limited by the minimum linear velocity required to produce a measurable velocity head. Thus, small gas flows will not actuate the steam control valves. This problem is usually overcome by installing a small bypass valve to permit a constant flow of steam to the flame burner. Attachments 14-5 through 14-7 show the steam-flow proportioning systems.

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2. Beychok, M., "Build a Flare for Under $5,000," *Petroleum Processing*, Vol. 8, p. 1162-1163 (1953).
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4. Decker, W. H., "Safe, Smokeless Combustion Features Waste Gas Burner at Sinclair Refinery," *Petroleum Processing*, Vol. 5, p. 965-966 (September, 1950).
5. Hajek, J. D., and Ludwig, E. E., "How to Design Safe Flare Stacks," Parts I and II, *Petroleum Engineering*, Vol. 32, p. C-31-38 (1960).
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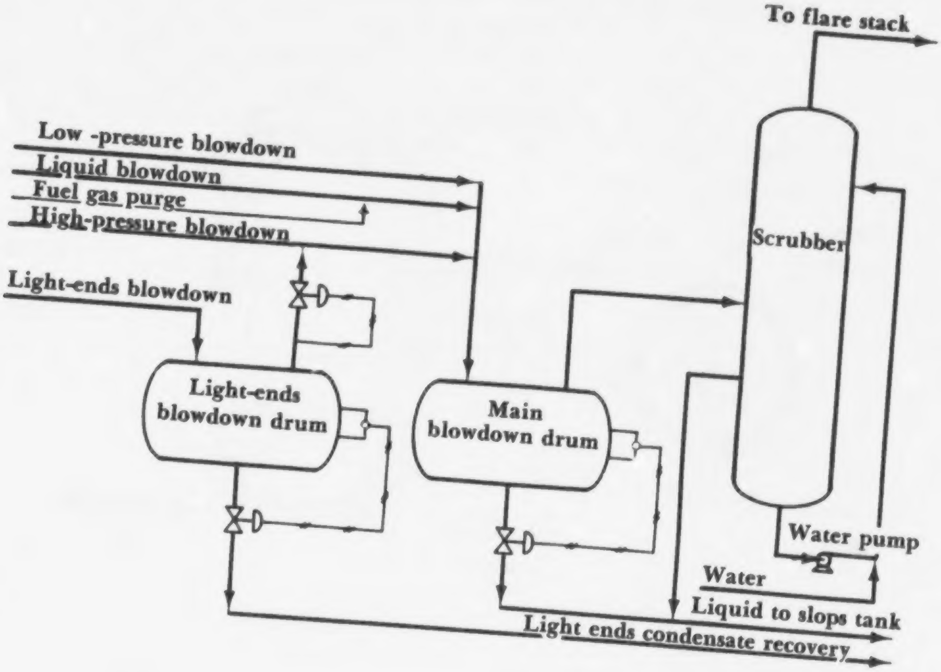
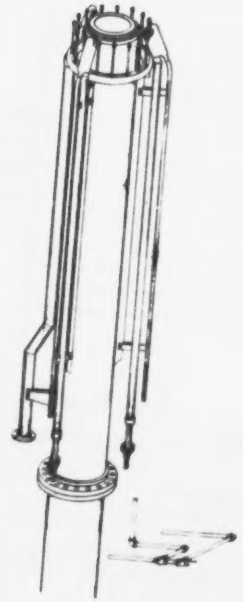
7. Smolen, W. H., "Smokeless Flare Stacks" *Petroleum Processing*, Vol. 6, pp. 978-982 (September 1951)
8. Smolen, W. H., "Design of Smokeless Flares," Paper presented at 17th API, Division of Refining Midyear Meeting (May 1952).
9. Reed, R. D., *Furnace Operations*, Second Edition, Gulf Publishing Co., Houston (1976).

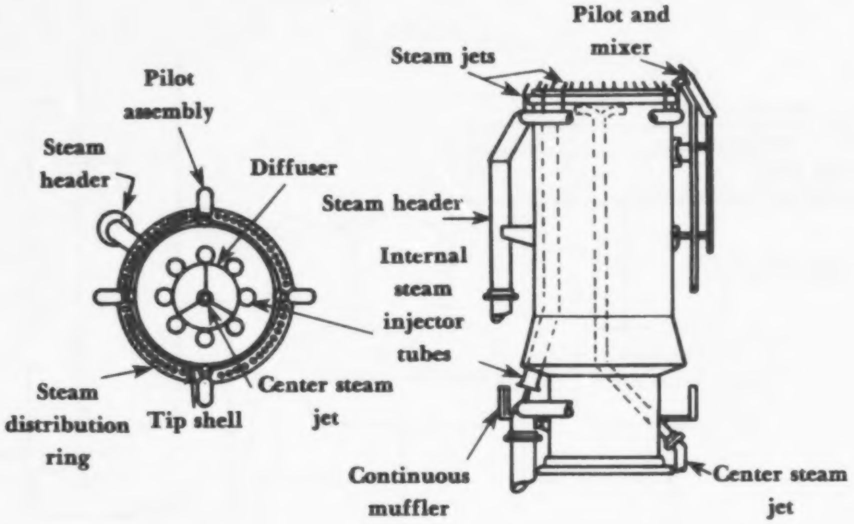
Attachment 14-1. Typical modern refinery blowdown system


To flare stack
Low -pressure blowdown
Liquid blowdown
Fuel gas purge
High-pressure blowdown
Light-ends blowdown
Light-ends blowdown drum
Main blowdown drum
Scrubber
Water pump
Water
Liquid to slops tank
Light ends condensate recovery



Attachment 14-2. View of John Zink smokeless flare burner (John Zink Company, Tulsa, OK)

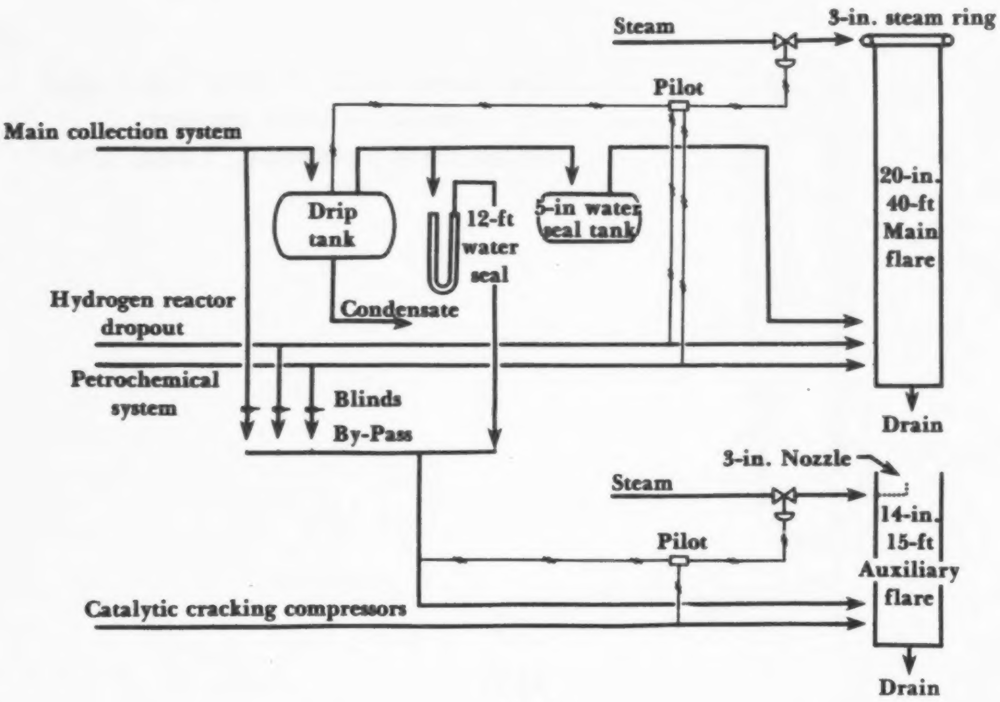
Attachment 14-3. Detail of flare tip showing internal steam injection (John Zink Company, Tulsa, OK)


Pilot assembly
Steam header
Diffuser
Steam distribution ring
Tip shell
Center steam jet
Pilot and mixer
Steam jets
Steam header
Internal steam injector tubes
Continuous muffler
Center steam jet

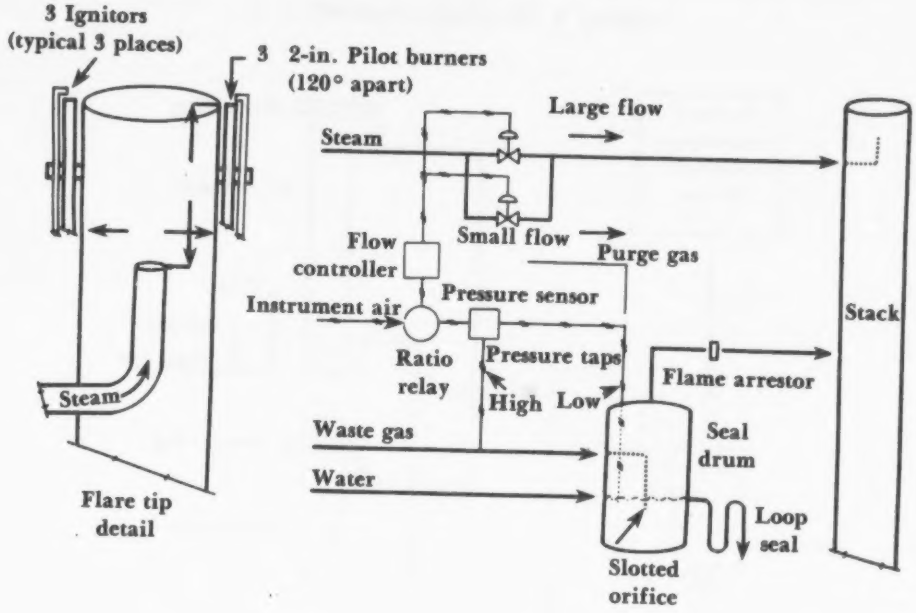
Plan

Elevation

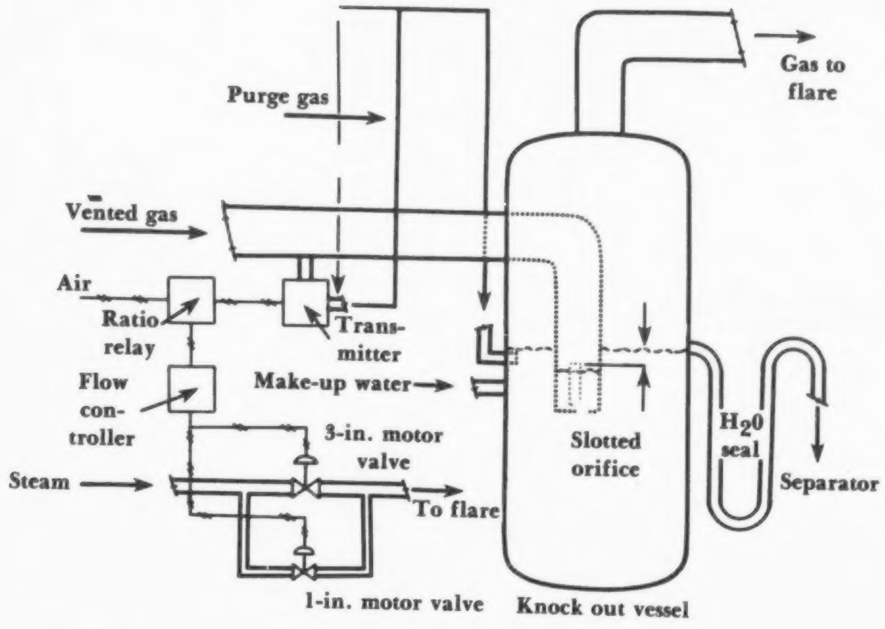
Attachment 14-4. Waste-gas flare system using multisteam-jet burner[3]


Steam
3-in. steam ring
Pilot
Main collection system
Drip tank
12-ft water seal
5-in water seal tank
20-in. 40-ft Main flare
Hydrogen reactor dropout
Condensate
Petrochemical system
Blinds
By-Pass
Drain
3-in. Nozzle
Steam
14-in. 15-ft Auxiliary flare
Pilot
Catalytic cracking compressors
Drain

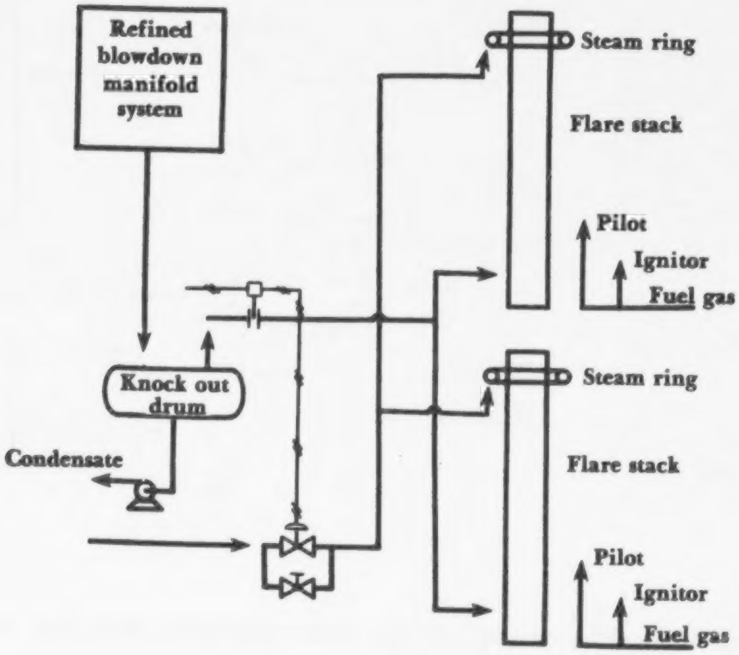
Attachment 14-5. Waste-gas flare system using Esso-type burner


3 Ignitors
(typical 3 places)
3 2-in. Pilot burners
(120° apart)
Steam
Flare tip
detail
Large flow
Steam
Small flow
Flow
controller
Purge gas
Instrument air
Pressure sensor
Ratio
relay
Pressure taps
High
Low
Flame arrestor
Stack
Waste gas
Seal
drum
Water
Loop
seal
Slotted
orifice

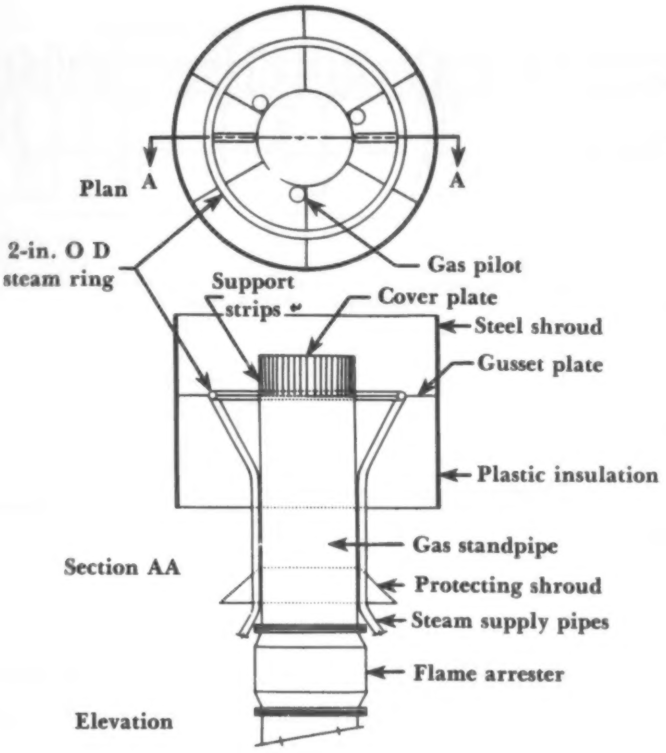
Attachment 14-6. Water seal drum with slotted orifice for measuring gas flow to flare


Purge gas
Gas to
flare
Vented gas
Air
Ratio
relay
Trans-
mitter
Flow
con-
troller
Make-up water
3-in. motor
valve
Steam
To flare
1-in. motor valve
Slotted
orifice
H_2O
seal
Separator
Knock out vessel

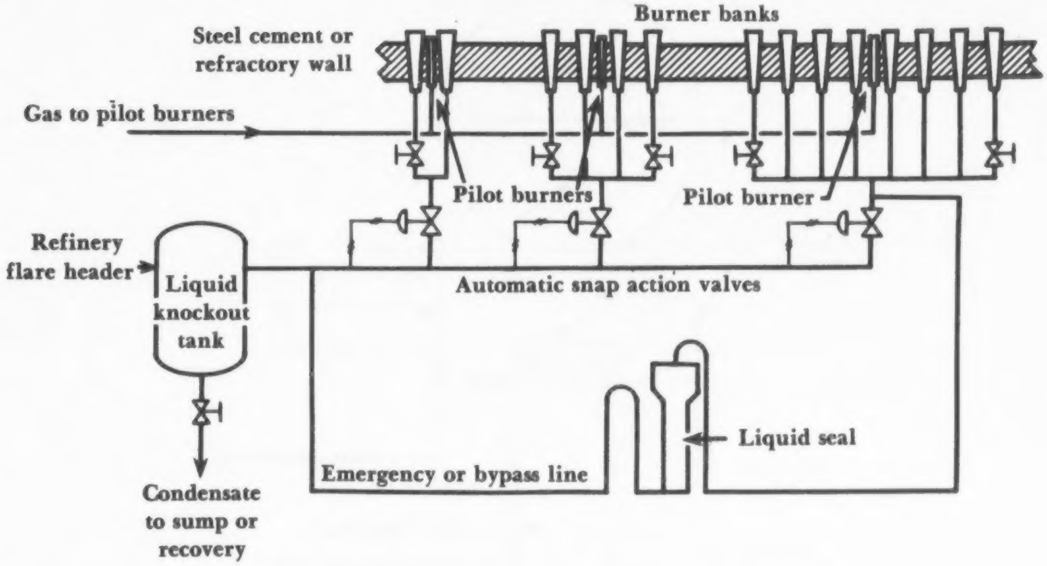
Attachment 14-7. Diagram of waste gas flare system using a Sinclair Burner


Refined blowdown manifold system
Steam ring
Flare stack
Pilot
Ignitor
Fuel gas
Knock out drum
Condensate
Steam ring
Flare stack
Pilot
Ignitor
Fuel gas

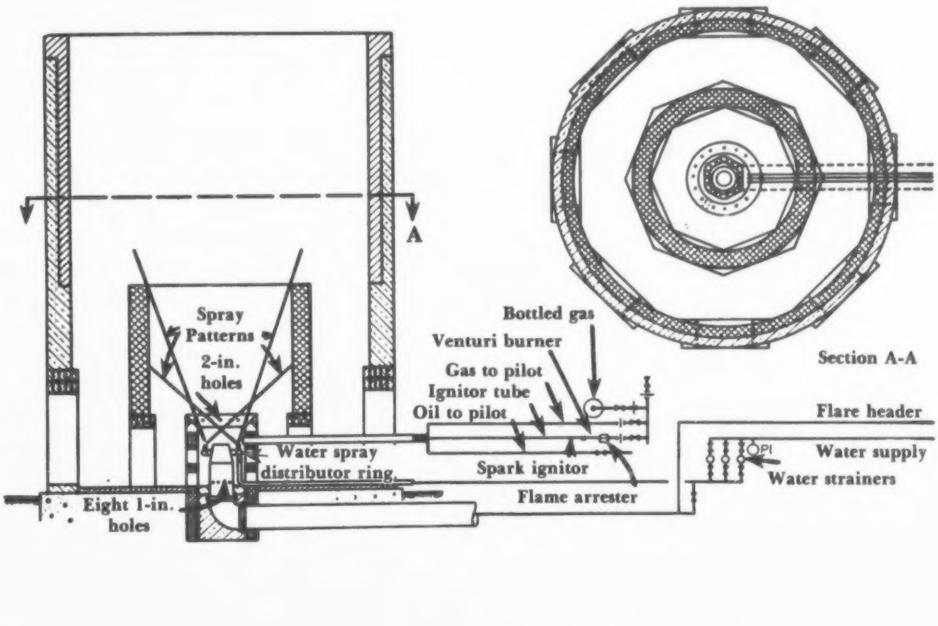
Attachment 14-8. Detail of Sinclair flare burner, plan and elevation[4]


Plan
A
A
2-in. O D steam ring
Gas pilot
Support strips
Cover plate
Steel shroud
Gusset plate
Plastic insulation
Section AA
Gas standpipe
Protecting shroud
Steam supply pipes
Flame arrester
Elevation

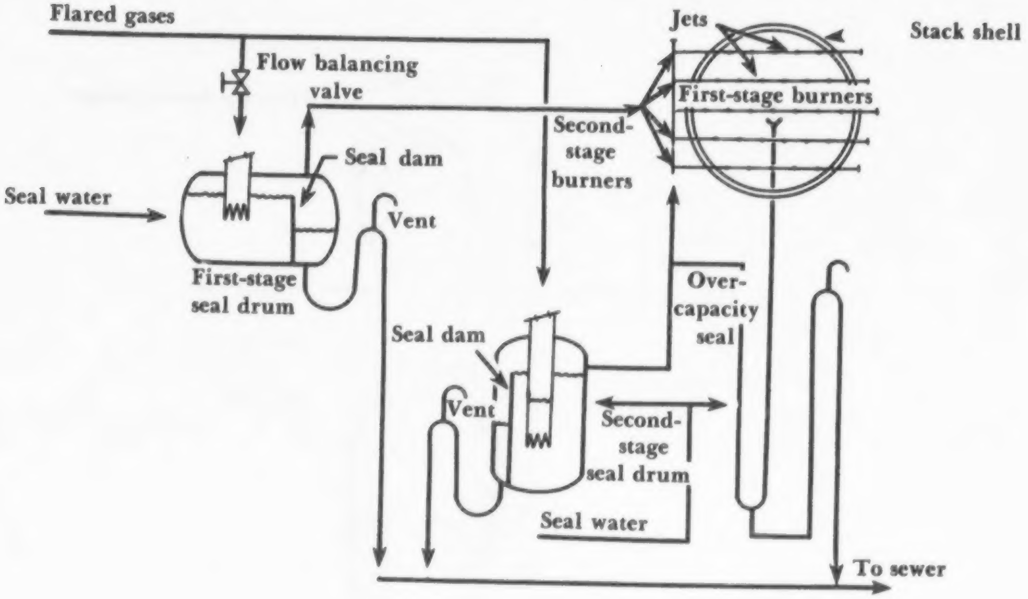
Attachment 14-9. Typical venturi ground flare, ignitors not shown[1]


Burner banks
Steel cement or refractory wall
Gas to pilot burners
Pilot burners
Pilot burner
Refinery flare header
Liquid knockout tank
Automatic snap action valves
Liquid seal
Emergency or bypass line
Condensate to sump or recovery

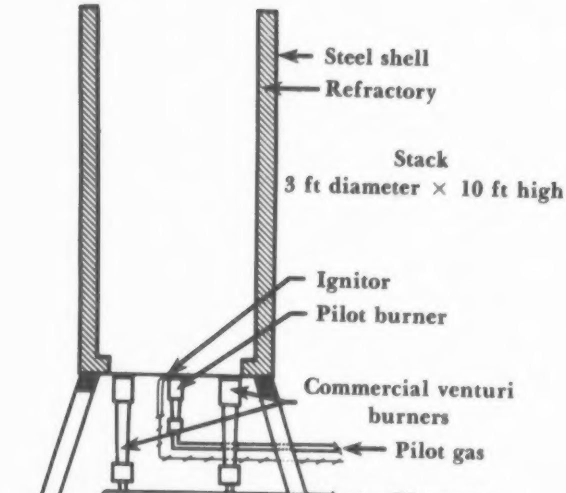
Attachment 14-10. Typical water-spray-type ground flare Six water sprays are shown. Two pilots and two ignitors are recommended [2]


A
Spray Patterns
2-in. holes
Bottled gas
Venturi burner
Gas to pilot
Ignitor tube
Oil to pilot
Water spray distributor ring
Spark ignitor
Flame arrester
Eight 1-in. holes
Section A-A
Flare header
PI
Water supply
Water strainers

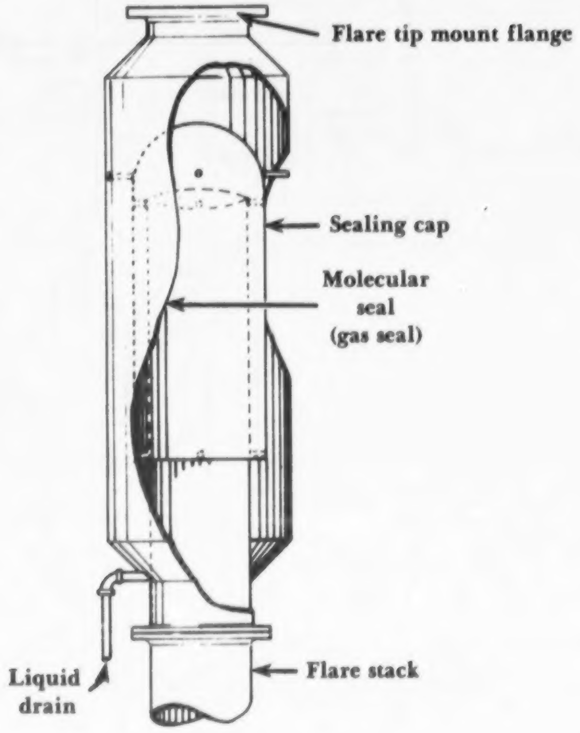
Attachment 14-11. Flow diagram of multijet-flare system[6]


Flared gases
Jets
Stack shell
Flow balancing valve
First-stage burners
Second-stage burners
Seal dam
Seal water
Vent
First-stage seal drum
Over-capacity seal
Seal dam
Vent
Second-stage seal drum
Seal water
To sewer

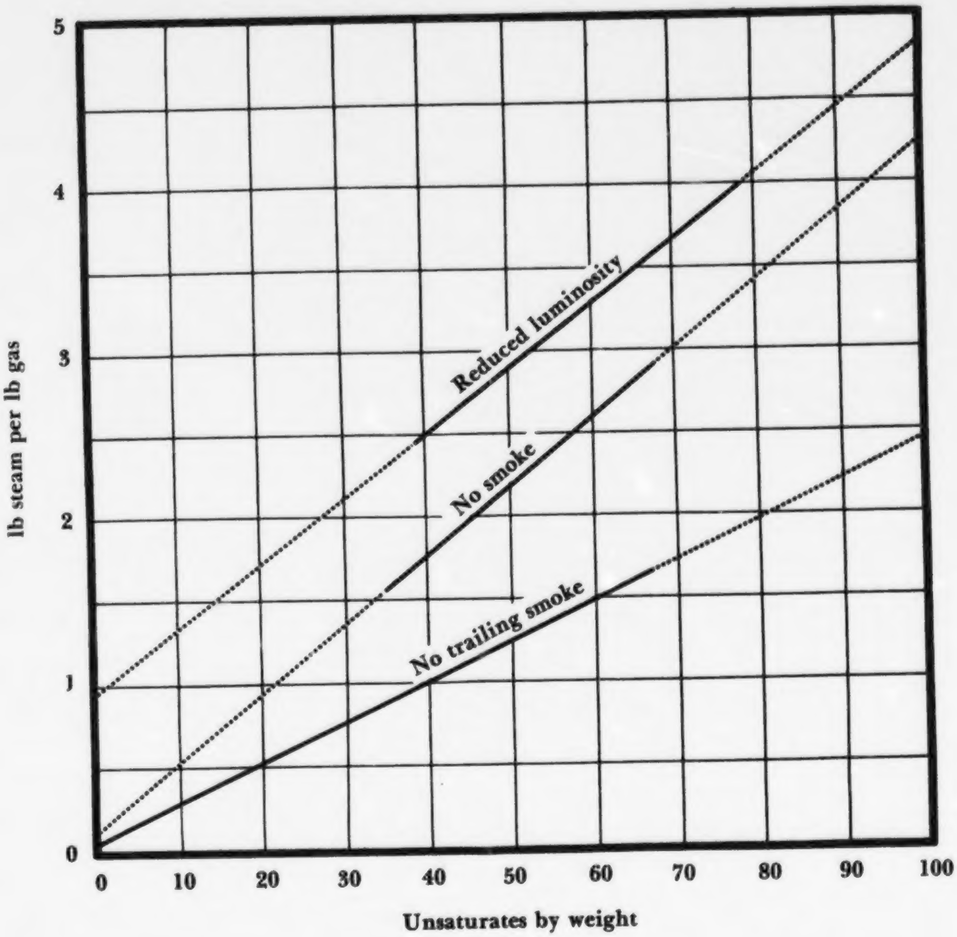
Attachment 14-12. Vertical venturi-type flare


Steel shell
Refractory
Stack
3 ft diameter × 10 ft high
Ignitor
Pilot burner
Commercial venturi burners
Pilot gas
Waste gas

Attachment 14-13. John Zink molecular seal (John Zink Company, Tulsa, OK)


Flare tip mount flange
Sealing cap
Molecular seal (gas seal)
Liquid drain
Flare stack

Attachment 14-14. Steam requirements for smokeless burning of unsaturated hydrocarbon vapor[1]



FLARE COMBUSTION

Leonard C. Mandell, P.E.*

I INTRODUCTION

"Flare Combustion" is a highly-specialized type of unsteady state, exposed-flame-burning - - - - into the free atmosphere. It has been developed mainly by and for the Petroleum Industry. Flares provide a means of safe disposal whenever it is impractical to recover large and/or rapid releases of combustible or toxic gases/vapors. These releases may occur under emergency conditions resulting from power or compressor failures, fires or other equipment breakdowns; or under day-to-day routine conditions of equipment purging, maintenance and repair, pressure-relieving and other unwanted accumulations - - - - such disposal being compatible with the public health and welfare. Flaring has become more of a safety or emergency measure. Combustible releases with heat contents as high as 4,000,000,000 Btu/Hr. have been successfully flared.

Flares must burn without smoke, without excessive noise, or radiant heat. They should have a wide capacity to handle varying gas-rates and Btu contents. Positive pilot ignition and good flame stability during adverse weather conditions are also necessary.

Typical gases that can be successfully flared range from the simple hydrocarbon alkanes through the olefins, acetylenes, aromatics, napthenes, as well as such inorganic gases as anhydrous ammonia, carbon monoxide, hydrogen, and hydrogen sulfide - - - - in fact, almost any combustible gas - - if feasibility so indicates.

Air Pollution can result from flare combustion. As we realize, pollution implies an adverse ecological situation. Air being man's universal and most vital environment makes the control of air pollution a major responsibility of The Public Health Profession.

A survey would indicate that air pollution means different things to people. However, all of these meanings can be placed in one of three categories, namely:

A Adverse effects upon our health

B Nuisance irritation to our basic senses

C Economic loss

These affects may occur singularly or in various combinations with each other. Experience has shown that the slightest unwanted change in the air causes great consternation among people. We have become accustomed to expect certain things from the air: that is, odorless, tasteless, and invisible - that it should be neutral in regard to its physical and bio-chemical effects. Further, air is expected to fulfill certain requirements that relate to our well-being and enjoyment, namely:

When respired, air will effect the metabolic needs for our activities without adverse physiological consequences of either an acute or chronic nature.

That air not be offensive to our basic senses of hearing, seeing, feeling, tasting or smelling.

That air not cause damage to our property, be it buildings, furniture, automobiles, livestock, vegetation, or other physical or animal assets - all of which would result in economic loss.

Accordingly, anything that modifies the nature of air as we have learned to know and enjoy it, may be called an Air Pollutant.

Flares may rightly be classed as significant, potential sources of local pollution because they can emit gases that are not only toxic but that can cause property damage, personal injury, nuisance and psychosomatic illness.

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Toxicity may evolve from the nature of the raw vent gases - - as the highly dangerous carbonyl chlorides and phthalic anhydrides, chlorine, hydrogen cyanide -- or from products of incomplete incombustion as phenols, aldehydes, organic acids, or from products of complete combustion as sulfur oxides and hydrochloric acid vapors.

Property damage may vary from being rather apparent as soiling from soot/smoke or heat-damage from radiant flames; or more subtle as from corrosive damage of sulfur trioxide, mist-size aerosols.

Personal injury may occur from falling and burning liquid aerosols that somehow should not have arrived at the burner-tip for flaring.

The nuisance aspect is excellently brought out by the odor problem from say hydrogen sulfide or the organic mercaptans. It should be noted that noise is also becoming a problem -- especially with high, specific steam ratios.

The psychosomatic aspect can be involved with ones knowledge of just the presence of the flare, (in his effective environment) whether it is creating an invisible-plume or a smokey, sunlight obscuring plume.

Hence, it behooves the "operators" to minimize these effects -- any of which can cause not only poor community relations but even costly litigation. It has been the author's experience that, as a rule, industry is desirous of being a good neighbor and will do the right thing if shown the need and if properly handled.

II BASIC THERMODYNAMICS

It should be noted that very few if any textbooks on combustion or thermodynamics contain any information on flares -- not withstanding the fact that successful flare-burning is a highly-specialized thermodynamic, combustion process. Perhaps, the reasons are that the universal need for flares is relatively very small and what information has been learned is treated as proprietary - and so kept confidential for business reasons.

III COMBUSTION - In General:

Any combustion gas can be completely oxidized if exposed to an adequately high temperature level for a long period of time in an atmosphere of sufficient oxygen and turbulence.

For purposes of this lecture let us look at combustion as a continuous, highly-complex, high-temperature, gas-phase oxidation process with very specific characteristics, namely:

A It involves a very rapid chemical reaction between the elements and compounds of hydrogen, carbon and sulfur and the oxygen in the air.

B That this reaction in order to be rapid enough requires fuel/air mixture temperatures much higher than the conventional ambient of 70°F, and within definite ranges of concentrations for various combustible compounds.

C That concurrent heat energy will for the most part be liberated and/or occasionally be required by the reaction to maintain its continuity. The common oxidation reactions of carbon, hydrogen and sulfur are exothermic liberating 14,500 BTU'S and 4000 BTU'S per lb. solid of carbon and sulfur, and 61,000 BTU'S/lb. of gaseous hydrogen respectively.

The water-gas reactions of:

1 $C + H_2O \rightarrow CO + H_2$

2 $C + 2H_2O \rightarrow CO_2 + 2H_2$

These reactions are quite rapid at temperatures greater than 1650°F.

require heat inputs of approximately 5900-6000 BTU/lb. carbon.

D That the combustion process requires close control of adequacy and intimacy of contact between the gas fuel and the oxygen molecules in order to obtain complete combustion; otherwise undesirable pollutants such as soot, smoke, aldehydes and carbon monoxide, etc. will be formed.

E That the reaction occurs with presence of a luminous flame. Certain Basic Concepts must be understood:

L. E. L. or Lower Explosive Limit or lower inflammable limit: This is the leanest mixture (minimum concentration) of the gas-in-air which will support combustion (where flame propagation occurs on contact with an ignition source).

U. E. L. or Upper Explosive Limit: This is the richest (Maximum proportion) of the gas in air which will propagate a flame.

Autogenous Ignition Temperature or Auto Ignition Temperature: The minimum temperature at which combustion can be initiated:

It is not a property of the fuel but of the fuel/air system. It occurs when the rate of heat gain from the reaction is greater than the rate of heat loss so that self-sustained combustion occurs.

Flame Propagation - The speed at which a flame will spread through a combustible gas-air mixture from its ignition source, it is usually lower at L. E. L. and the U. E. L., and higher at the middle of range.

Flame: A mass of intensely, heated gas in a state of combustion whose luminosity is due to the presence of unconsumed, incandescent, fractional-sized, particles - mainly carbon. (Small particles of suspended carbon/soot formed by cracking of hydrocarbons). Visibility ceases at complete combustion or where the glow of the ash ceases.

Infra Red Radiation: Is, for the most part an invisible, electromagnetic phenomena. Relatively large amounts of heat are radiated at elevated temperatures by such gases as carbon dioxide, water vapor, sulfur trioxide, and hydrogen chloride. The I. R. spectrum begins at 0. 1 micron wave length and extends up to 100 microns. For reference, I. R. solar radiation (10, 240°F) lies within the 0. 1 to 3 micron range. (We know that a large proportion is emitted in the visible band of 0. 4 to 0. 8 micron. A 2300°F black body emits most of its energy between 0. 7 and 40 microns. For the discussion at hand, (temps between 1500 and 2500°F) radiant emission may be assumed between 0. 5 micron and 50 microns with maximum intensity occurring at the 2 micron wave-length.

Timing is important in that the attainment of satisfactory combustion requires sufficient, high-ambient, reaction temperatures, and an adequate oxygen-fuel mixing. Both phenomena are related to time/probability functions.

IV BASIC COMBUSTION CONCEPTS AS APPLIED TO FLARES:

A Gaseous fuels alone are flared because they:

- Burn rapidly with very low percentage of excess air resulting in high flame temperatures.

Leave little or no ash residue.

Are adaptable to automatic control.

B The natural tendency of most combustible gases when flared is smoke:

An important parameter is the H/C ratio. Experience has shown that with hydrocarbon gases such as: Acetylene (C_2H_2) with a H/C ratio = 0. 083, real black soot will result from simple burning.

Propane (C_3H_8) with a H/C ratio = 0. 22 creates black smoke.

Ethane (C_2H_6) with a H/C = 0.25 - a bright yellow flame with light trailing smoke will result. A H/C of 0.28 gives very little if any smoke, and methane (CH_4) with a H/C of 0.33 gives a bright yellow flame with no smoke.

If the H/C is less than 0.28, then steam-injection close to the point of ignition into the flame makes the flare smokeless. It should be noted that steam injection can be applied to the point of clearing up the smoke and reducing luminosity before reaching the point of extinguishing the flame. Hydrogen is the cleanest, most rapid and highest-heat evolving fuel component. It helps to: heat the carbon and also provides for better carbon/oxygen contact which results in cleaner burning; also, the reaction of carbon monoxide to carbon dioxide goes much easier in the presence of water vapor.

C In flare burning of sulfur-bearing compounds: approximately 90% or more appears as sulfur dioxide and 10-30% of the (SO_2) mutually appears as sulfur trioxide. Blue grey smoke becomes visible as the sulfur trioxide falls below its dew point temperature.

D In flare burning of chlorine-bearing compounds, most will appear as hydrogen chloride vapor. However, appreciable quantities of chlorine will remain.

E A relation exists between the auto-ignition temperature of the gas, its calorific value and its ease of successful flare burning.

At 800°F AIT: A minimum H.V. of 200 BTU/cu. ft. is required.

At 1150°F AIT: A minimum H.V. of 350 BTU/ cu. ft. is required.

At 1300°F AIT: A minimum H.V. of 500 BTU/cu. ft. is required.

F Since the heat content of many gases vary much below 100 BTU/cu. ft. and since complete burning is required regardless of the weather; pilots are used to initiate ignition of the flare gas mixtures, -- and to help maintain flame temperatures to attain rapid burning.

G Yellow-flame combustion results from the cracking of the hydrocarbon gases that evolve incandescent carbon due to inadequate mixing of fuel and air. - Some flames can extend to several hundred feet in length.

H Blue-flame combustion occurs when water (steam) is injected properly to alter the unburnt carbon.

I Actual Flare Burning Experience (John Zink Company)

(Dilution/Temperature Effects for acetylene in air)

C_2H_2 @1800°F temperature will burn completely in 0.011 sec -- 50% Dilution

C_2H_2 @ 1800°F temperature will burn completely in .016 sec. -- 75% Dilution

C_2H_2 @ 1800°F temperature will burn completely in .034 sec --90% Dilution

C_2H_2 @ 1800°F temperature will burn completely in .079 sec --95% Dilution

C_2H_2 @ 1800°F temperature will burn completely in 1.09 sec --99% Dilution

C_2H_2 @ 1800°F temperature will burn completely in 4.08 sec --99.5% Dilution

Note: The 4.08 sec. time @ 1800°F falls to less than 1 sec. @ 2000°F temperature.

J Flared gases must be kept at temperatures equal to or greater than auto ignition temperature until combustion is complete.

K Carbon monoxide burns rapidly with high heat and flame temperature, whereas carbon burns relatively slow.

L A smokeless flare results when an adequate amount of air is mixed sufficiently with fuel so that it burns completely before side reactions cause smoke.

What is Required? Premixing of air + fuel

Inspiration of excess air into the combustion zone

Turbulence (mixing) and time

Introduction of steam: to react with the fuel to form oxygenated compounds that burn readily at relatively lower temperatures; retards polymerization; and inspirates excess-air into the flare.

Note: 1) Steam also reduces the length of an untreated or smokey flare by approximately 1/3 of its length.

2) With just enough steam to eliminate trailing smoke, the flame is usually orange. More and more steam eliminates the smoke and decreases the luminosity of the flame to yellow to nearly white. This flame appears blue at night.

M The luminosity of a flare can be greatly reduced by using say 150% of steam required for smokeless operation. Since a major portion of flame originates from contained incandescent carbon.

N Water sprays, although effective in low-profile, ground-flares, have not been effective to date in elevated flares. The water although finely atomized, passes out and away from the flame without vaporizing or intimately mixing with burning gases -- especially where any kind of wind occurs. The plugging of spray nozzles is also a problem - the "Rain" from spray that may fall near base of stack is very corrosive.

Note: Recent water shortages dictate the use of steam since specific water wastes of 1-2 lbs. water/lb. of gas is customary.

Approximately 2-3 times as much water as steam is needed for ground-level flaring.

O The following table summarizes some pertinent gas characteristics for flaring.

GAS PROPERTIES RE-FLARING

Element/ Compound	Mol. Wt.	H/C	AIT	" % by Vol. in Air" LEL	UEL	Btu/cu. ft. Net	Flame Temp-°F	Flame Speed
H_2	2		1000-1100°F	4.1	74	275	4100°F	1-16'/Sec.
C_2H_2	26	.083	600- 800°F	2.5	80	1435	4200	2-5
NH_3	17		1200	16	27	365		
H_2S	34		550- 700	4.3	46	596		
CO	28		1200	12.5	74	321	4200	1-4
C_3H_8	44	.222	1000-1100	2.1	11.4	2360		
CH_4	16	.33		5.3	14.0	914	3800	.8-2.2
HCN			1000					
C			750°					
S			470°					
C_2H_4	28	.17		3	29	1512		
C_4H_6	54	.13		2	11.5	2840		

V TYPES OF FLARES:

Flares are arbitrarily classed by the elevation at which the burning occurs; i.e. -- The elevated-flare, the ground-flare and the-Pit. Each has its pros and cons. As should be expected, the least expensive flare will normally be used to do the required job-compatible with the safety/welfare of the Company and the Public.

A The Pit: The venturi type is, as a rule, the least expensive. It can handle large quantities such as 14,000 cfm or 20,000,000 cu. ft./day. It consists of one or more banks of burners set horizontally in a concrete/refractory wall. The other three-sides are earth-banks approximately 4 ft. high. The typical ground-area may be approximately 30 ft × 40 ft. The pit excavation may be 6 ft. deep, all burners discharge horizontally. The burners may vary from the simple orifice to the better venturi - aspirating units with pressure-valve regulation. Piping and appurtenances include proper pitch, knock-out drums, liquid seals, and constant-burning, stable pilots. As a rule, burning pits are the least satisfactory but also are least expensive. However, if location and air pollution are not significant, the pit method becomes attractive.

Note: Rothschild Oil built a 2,000,000 Scfd (standard cubic feet per day unit) in 1953 for $5,000.00.

B Ground Flares: In general, ground flares require approximately 2½ times as much steam to be smokeless as elevated flares. They also require much more ground space. At least a 500 feet radius should be allowed all around the flare. In addition to the burner and combustion auxiliaries, ground flares also require a ground-shield for draft control and at times a radiant shield for heat and fire protection. Hence, large open areas are needed for fire-safety (plenty of real-estate) and air pollution attenuation. Ground flares do however offer the advantages of less public visibility and easier burner maintenance. The cost of present-day, ground flares as a rule are more expensive than elevated flares. However, they may also cost less depending upon location requirements. Ground flares are normally designed for relatively small volumes, with a maximum smokeless operation up to approximately 100,000 standard cubic feet per hour of butane or equivalent. There is heat sterilization of areas out to a radius of approximately 100 ft. At least 3 types are known to the author; the Esso multi-jet smokeless and Non-Luminous Flare, the conventional center nozzle with spray water for inspiration of combustion-air; and the dry-type for clean burning gases.

Typical water spray flare-design requirements are;

> The spray must intimately mix with the burning gases
>
> These gases require an outer shell to retain heat and flame.
>
> Combustion air of at least 150% must be allowed to enter the base through the surrounding shells. The higher the molecular weight of the gas, the greater the spray rate: Example:

200,000 Scfhr. M. wt. = 28	30-40 psig. @35 gpm. is required.
200,000 Scfhr. M. wt. = 37	120 psig.@ 80 gpm. is required.

Back in 1959, Esso Research developed the Multi-Jet Flare. It operates in a smokeless and non-luminous manner with very little noise. The flare requires little of the conventional auxiliaries. It consisted of a series of rows of horizontal pipes containing 1 inch diameter jets that served as burners. These burners were located at the base of the stack approximately 2 ft. above ground level. The jets require flame-holders (rods) to provide time and turbulence for adequate air-mixing for smokeless combustion. A 32 ft. high stack was required to shield the flame. A 3 ft. diameter flare handled up to 140,000 standard cubic feet per day and a 6 ft. diameter stack up to 600,000 Scf/day. It operated with a 25 ft. high flame. A cost comparison with other flares types at that time was made: - Based on 12,000,000 Scf/day of a 40 Mol. wt. gas, the multi-jet cost $148,000. This was twice the cost of an elevated flare without steam, or one half the cost of an elevated flare with steam. This was also about the same cost as a ground-flare with water.

C Elevated Flares:

This type of flare provides the advantages of desirable location in associated equipment-areas with greater fire and heat safety: also considerable diffusion/dilution of stack concentrations occur before the plume-gases reach ground level.

Major disadvantages are:

1 Noise problems result if too much steam is used

2 Air vibrations severe enough to rattle windows 1/2 mile or more away.

There are 3 general types:

The non-smokeless flare which is recommended for relatively clean, open-air, burning gases such as hydrogen, hydrogen sulfide, carbon monoxide, methane, and ammonia.

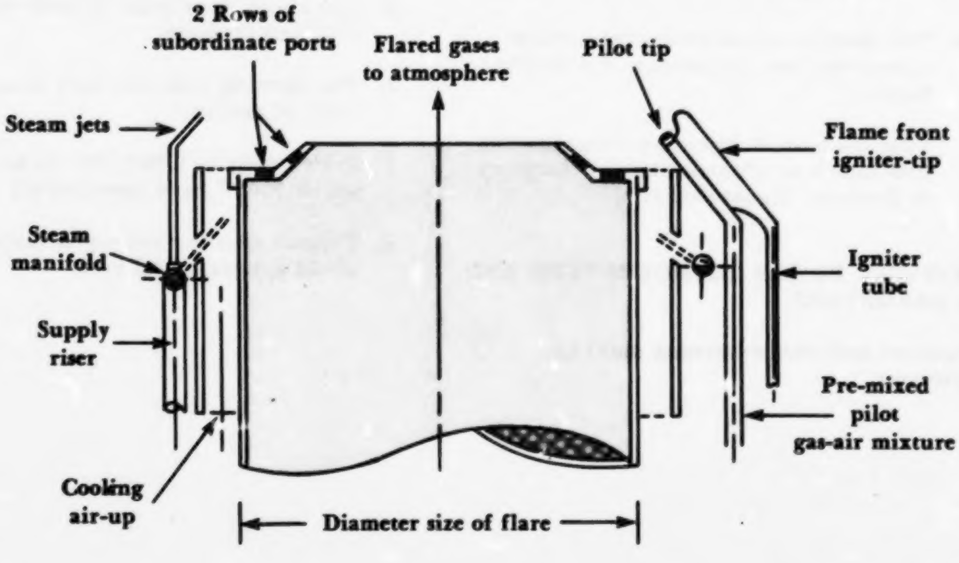
The smokeless flare which incorporates steam injection to obtain clean burning of low H/C ratio gases such as acetylene, propylene, and butadiene.

The endothermic type which incorporates auxiliary means of adding heat energy to the vent gases of low heat contents in the 50-100 BTU/cu. ft.). This flare may or may not operate smokelessly.

Elevated flares require special burner tips, special pilots and ignitors, wind screens, refractory lining, and instrumentation--for acceptable performances.

Let us take a moment and review what happens at the flare-tip.

HAPPENINGS AT THE FLARE TIP:


2 Rows of subordinate ports
Flared gases to atmosphere
Pilot tip
Steam jets
Flame front igniter-tip
Steam manifold
Igniter tube
Supply riser
Pre-mixed pilot gas-air mixture
Cooling air-up
Diameter size of flare

Gas is ignited just as it reaches the top of the stack. Before adequate oxygen/fuel mixing can occur throughout the entire gas profile certain things occur:

Part of the gas burns immediately resulting in an oxygen deficiency which induces carbon-formation.

The unburned-gases crack to form smaller olefins and paraffins; and at the same time some molecules polymerize to longer chain hydrocarbons. More carbon is created from combustion of these newly formed compounds in a reducing atmosphere.

The long, luminous-flame in ordinary flaring is made up of incandescent, carbon particles which form smoke upon cooling. Steam-mixing suppresses carbon formation by:

a) Separating the hydrocarbon molecules, thereby minimizing polymerization.

b) Simultaneously forming oxygenated compounds which burn at a reduced rate/temperature not conducive to cracking/polymerization.

Note: The absence of incandescent carbon also gives the appearance of a shorter flame.

That the idea of injecting water/steam into flares originated at Esso Refinery in Everett, Massachusetts.

VI TYPICAL DESIGN CONSIDERATIONS AND PARAMETERS

A Ignition and stable-burning must be insured.

B Capacity must handle the maximum expected quantity if toxic, or a statistical compromise of the maximum expected release. This may indicate normal operation of 1-5% of these capacities.

C Pilots must be stable in high winds (80 mph) and heavy rains.

D Pilots must be ignitable in high winds (80 mph) and heavy rains.

E The height of the flare is determined by fire and heat safety. Dilution may also be important from an air pollution standpoint.

F Steam requirements are related to the H/C ratio (wt.). For H/C ratios greater than 0.33 - no steam is needed. Lower ratios can demand up to 2 lbs. steam/lb. of vent-gas to obtain smokeless operation. As a rule, 0.6 lb/lb. appears to be the average required. Steam requirements are proportional to the degree of unsaturation and the molecular weight of the gas being flared. Flares are designed to be smokeless for up to 15% of capacity only.

G Sizes may vary from $1\frac{1}{2}$ inch pipe to 120 inch diameter.

H The burning rate can vary from 0.5% - 100% of design.

I Systems up to 1,000,000 lb/hr. of 43 mol. wt. @ 700°F have been flared. (Zink)

J Typical data for hydrogen sulfide flares would appear as follows:

DATA	SIZE OF FLAME	
lbs/hr:	600 lbs/hr.	10,000 lbs/hr
cfm	112 cfm	1900 cfm
cfday	164,000 of day	2,750,000 cf day
flare size	2 inch diameter	12 inch diameter
cost installed	$2300	$5800
type	non smoking	non smoking
steam	no'	no'
flame dimensions	10 ft. ht. × 1 ft. diam.	40 ft. long × 3 ft. diam.
Ht. above ground to negate heat effects from flame	50 inch*	85 inch*

* May be much higher for air pollution control.

K It should be noted that radiant, flame effects can be serious. Radiation and solar heating should not exceed 1000 BTU/Hr./Sq. Ft. at ground level with 700 BTU/Hr./Sq. Ft. from the flame and 300 from the sun. (Zink)

L The ignitors operates only to start the pilot. The pilot burns continuously. A 2-3 inch diameter flare requires one pilot. A 4-6 inch diameter flare requires two pilots and flares greater than 6 inch diameter requires three pilots.

M Auxiliary heat is needed for gases with lower heating values of from 50-100 BTU/cu. ft.

N Flare heights range from 25-375 ft. with flame radiation being the determining factor.

O Hydrogen, carbon monoxide, and ammonia burn smokelessly without assistance.

P Tendency for smoking begins at H/C of 0.25 and becomes heavy @H/C of 0.20.

Q In general, flare operation of gases less than 150 BTU/cu. ft. heat content becomes quite critical in point of maintenance of ignition in all-weather conditions. Here endothermic design is needed. Only very few are in use. Usually they are limited by economics to sizes less than 5,000,000 BTU/hr equivalent of auxiliary fuel.

R Steam may also be required for preheating in very cold areas -- besides being needed for smoke control.

VII AUXILIARIES REQUIRED FOR SUCCESSFUL FLARE OPERATIONS:

A Flare Tips of Inconel or other stainless alloys with steam jets, air cooling, stabilizing parts, etc.

B Ignitors are used to light the pilot at start-up or at Pilot flame failure.

C Pilot Burners to light flare and keep it lit

D Mist Trap: to remove fine, liquid aerosols from reaching the stack.

E Flame arrestor: to prevent flame-travel back into piping.

F Liquid seal: To reduce pulsations from surges: to prevent air from entering vent-gas lines: to prevent reverse-flame, flash-back.

G Flow Sensors for steam control

H Pilot flame detectors

I Auto reignition system for pilots

J Shrouds are not of real value in smoke control, however, they can be used in preventing downwash.

Note. The pilots initiate combustion of the flared gases. They also help to heat and maintain flame temps. The ignition system consists of premixed 15 psig. fuel gas/air mixture that is pre-ignited in a special in-line, pipe-chamber by a spark plug. The flame-front, under flow-pressure, travels through a 1 inch igniter pipe to the tip of the pilot burner. Once the pilot is ignited, the fuel and air valves are closed. Time for ignition of all 3 pilots averages 1-2 minutes. Pilots must burn at a rate of at least 30,000 BTU/hr. each.

VIII MATERIALS OF CONSTRUCTION:

Reflection will indicate that many flare-gases are corrosive at normal atmosphere temperatures. Chemical activity, as a rule, increases with increasing temperatures. Hence, the selection of suitable materials for the handling/conveying of these gases -- especially at the flare-tip becomes significant to the feasibleness of this particular method of combustible, gas disposal.

It should be remembered that metals or alloys provide the function of corrosion-resistance by either formation of a surface film or resistance to chemical activity with the environmental materials. Accordingly, other corrosive factors as gas velocity, thermal shock and catalytic influences must be considered in addition to temperature effects. Another practical consideration is the deleterious carbide precipitation that results from the welding process. It removes some of the corrosion resistant and strength constituents from the alloy.

The stainless-steel, iron alloys (approximately 74% steel) are at present, the most feasible metals for flare construction. The stainless steels compose a class of nickel and chrominum alloys that owe their corrosion resistance to the high metal content and the strength to the chromium. Tenacious, protective film develops ----- especially in oxidizing atmosphere. Typical stainless compositions are:

TYPICAL STAINLESS STEEL ALLOYS

ALLOY	% Cr	% Ni	% C	% Mo	% Si	% Mu	Co
304	18-20	8-10	.08 max.		.75 max.	2.0 max.	
316	16-18	10-14	.10	2-3	.75 max.	2.0 max.	
347	17-19	9-12	.10		.75 max.	2.0 max.	1.0% max.
430	14-18	----	.12		.75 max.	0.50	
Hastelloy's	X	X		X			
Inconel (6% Fe)	10	84					

Leading suppliers of special stainless steels are International Nickel Company; Haynes Stellite, Division of Union Carbide; Carpenter Steels, etc.

Experience has shown that:

Type 304 s. steel is satisfactory for 1600°F -sulfur exposure

Type 309 s. steel is satisfactory for 2000°F -sulfur exposure

Inconel - a high heat resistant alloy for hydrogen sulfide, but not satisfactory for hydrogen chloride, sulfur dioxide or sulfuric acid vapors.

Hastelloy - (special s. steel) manufactured by Haynes Stellite is good for SO_3, H_2SO_4 and Hcl.

Hastelloy B for chlorine resistance, H_2SO_4

Hastelloy A for Hcl, H_2S, SO_3, H_2SO_4

Type 430 is suitable for general use up to 1600°F

In the final analysis of material selection, the cost of replacement must be carefully weighed against the longer life and higher initial cost of the most resistant materials.

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1 American Petroleum Institute, N.Y. Manual on Disposal of Refinery Wastes, Volume II Waste Gases and Particulate Matter, 1957.

2 Reed, Robert D. John Fink Co., Tulsa, Oklahoma, Private Communications, 1966.

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4 The Various Petroleum Companies, (such as Shell, Esso, Gulf) Research and Engineering Departments.

5 Petroleum Processing Journals.

Chapter 15

Combustion of Hazardous Wastes

Government, industry, and environmental groups have become increasingly aware of the need for environmentally acceptable ways of treating and disposing of industrial wastes in general and hazardous wastes in particular. Incineration provides one possible method to dispose of a large number of combustible waste materials.

Among the advantages of using incineration for waste disposal are:

- Combustion technology is reasonably well developed.
- Incineration is applicable to most organic wastes.
- Heating value of combustible wastes may be recoverable.
- Large volumes can be handled.
- Large land area is not required.

There are, of course, some disadvantages as well:

- Requires costly equipment which may be complicated to operate.
- May require auxiliary energy.
- Not always the ultimate disposal—solid residue (ash) may be toxic.
- Combustion products may be polluters which are hazardous to health or damaging to property.

The decision on whether or not to use incineration will depend on its environmental adequacy and total costs, in comparison with other disposal options.

Many types of incinerators have been used for thermal destruction of hazardous materials. These include rotary kilns, multiple-hearth incinerators, liquid-injection incinerators, fluidized beds, molten salt devices, wet oxidation, plasma destructors, multiple-chamber incinerators, gas combustors, and pyrolysis units. The operation and capabilities of these devices has been summarized (1), based primarily on the TRW Systems, Inc. report entitled "Recommended Methods of Reduction, Neutralization, Recovery, and Disposal of Hazardous Waste"(2), where some results on incineration of specific materials are presented as well.

Knowledge of specific incineration criteria for individual wastes is still very limited. Generally speaking, only organic materials are candidates for incineration, although some inorganics can be thermally degraded. Halogen-containing organics emit extremely corrosive hydrogen halides necessitating careful selection of materials for construction and scrubbing of emissions. Organic materials containing dangerous heavy metals (such as *Hg, As, Se, Pb, Cd*) should not be incinerated unless the emissions of the metal components into the environment are known to be harmless or can be controlled by pollution control equipment. SO_X emissions from sulfur-containing materials may need to be removed if present in appreciable concentrations. NO_X formation can be minimized by keeping incineration temperatures low—below about 2,000°F. The destruction ratio of a given material by incineration depends to a large extent on the temperature and the dwell (residence) time at that temperature. Incinerators burning hazardous wastes should be equipped with automatic feed cut-off provisions in the event of either a flame-out or a reduction in reactor temperature below that required for complete combustion.

Halogenated and Sulfonated Materials

Chlorinated and sulfonated solvents can be handled by incineration, but this alone will not eliminate air pollution. Chlorinated hydrocarbons with hydrogen-to-chlorine ratios of at least 5:1 yield hydrogen chloride; those hydrocarbons with ratios less than this are likely to yield other chlorinated products which are difficult to collect. To avoid the latter problem, excess natural gas or steam needs to be injected to produce HCl, which will then have to be scrubbed from exhaust gases. Note that flaring chlorine-containing substances is not an acceptable control technique, and it is to be considered for emergencies only.

Scrubbing of incinerator exhaust can be accomplished by conventional spray or packed-tower-type scrubbers, or by submerged combustion incineration (3) as shown in Attachment 15-1. Similar systems for liquid waste disposal are discussed in References 4 and 12. The scrubber liquor has to be neutralized before disposal. Attachment 15-2 illustrates a water quench and a scrubber combination for cleaning the incinerator exhaust from halogenated liquid waste which was treated at 1,800°F for one second (12). Water scrubbing will not be sufficient to eliminate SO_X produced by the incineration of sulfonated materials. Caustic solution or lime slurry are used for this purpose.

Chlorinated and fluorinated plastics—such as PVC, Teflon, and others—can present considerable disposal problems. Incinerations of these materials or their gaseous monomers will release HCl and HF, which are not only serious pollutants, but also very corrosive. Exhaust gas cleaning is therefore required, usually by some type of scrubbing device.

Pesticides and Toxic Wastes

Incineration, in addition to being used for volume reduction and energy recovery, can be used to detoxify many organic materials if the toxicity or the hazardous property is due to the chemical structure of the molecule, rather than a property of the elements it contains. A large number of compounds of nominal toxicity are thus amenable to thermal destruction. Pesticides, which have been withdrawn from use or have become obsolete, and components of hazardous industrial wastes fall into this category. Thermal destruction of such materials is an extremely complex process, and little is known about the mechanisms of this disposal technique.

However, the following general conclusions can be drawn from the experience gained so far with pesticide incineration (5, 6):

- Most pesticides can be destroyed by incineration with over 99.99% of the active ingredient detoxified.
- The most important operating variables are temperature and retention time in the combustion chamber.
- Certain conventional incinerators have the potential for incinerating pesticides if adequate retention times at the appropriate temperatures can be obtained and emission control devices provided.

- Residues left from the incineration of formulations with inert binders and carriers, generally contain very low levels of pesticides, e.g., less than 20 ppm.
- Incineration of organonitrogen pesticides can generate measurable quantities of cyanide (CN^-) at temperatures tested (650 – 1,050 °C).
- Odor can be a potential operational problem, particularly with organosulfur pesticide incineration.

Temperatures and retention (dwell) time requirements for pesticide incineration are generally higher than for hydrocarbons in conventional afterburners, as shown in Attachment 15-3 (5). Zone A represents operating conditions where less than 99.99% destruction may result, whereas conditions in Zone B are anticipated to yield greater than 99.99% destruction. In the operating zone, the acceptable range for excess air is estimated at 80 to 160%.

Since smaller quantities of pesticides and other toxic materials will inevitably escape any type of combustion and air pollution control system, environmental considerations must be emphasized when pesticide incinerators are sited and sized.

All types of incinerators are not compatible with disposal of all classes of pesticides. While requirements for combustion of certain classes of pesticides are readily achieved by many incinerators, other classes require extreme conditions which necessitate custom designs with sophisticated operating and monitoring programs.

The serious environmental contamination of a Kepone manufacturing facility and its environs near Hopewell, Virginia have increased the efforts to develop acceptable technologies for the disposal of unwanted pesticides and pesticide-contaminated solid wastes. Work on Kepone has found it to be definitely more thermally stable than DDT (7). A comparison of the thermal destruction of several pesticides is shown in Attachment 15-4. Any incineration requirements for Kepone should therefore, at a minimum, meet those for DDT, which have been established at 1,000 °C for two seconds (8). This could be accomplished in a system illustrated in Attachment 15-5 consisting of a rotary kiln pyrolyzer, followed by a fume incinerator (afterburner) and a scrubber. Destruction efficiencies in excess of 99.999% were achieved in such a device capable of maximum feed rates of approximately 100 lb/hr (7).

Incineration of PCBs

Polychlorinated biphenyls (PCB) are extremely stable and persistent synthetic compounds which have been found to be dangerous to certain species and ecosystems. Studies have been undertaken to establish the criteria for thermal destruction of PCBs and related compounds (9). It was found that PCBs are more stable thermally than Mirex—a very stable pesticide, as shown in Attachment 15-4. When exposed to a very high temperature (1,000 °C for one second in air), PCB destruction of greater than 99.995% can be achieved. Under thermal stress, PCBs can decompose to lower molecular weight products which were not identified in this study (9). Compounds related to PCB's exhibit similar thermal destruction behavior as PCB mixtures.

Waste Propellants, Explosives, and Pyrotechnics

Incineration appears, for the foreseeable future at least, to be the primary acceptable destruction method for waste ordnance and propellants, explosives, and Pyrotechnics (PEP) materials. The method of feeding the ordnance and PEP to an incinerator for disposal is very important for safety reasons. In the batch process, an even layer of PEP is distributed in the incinerator prior to disposal. The continuous feed method dilutes the PEP materials with sand, sawdust, or water. The amount of feed and the dilution ratio is limited by safety considerations.

A rotary kiln-type incinerator with fire-brick lining (Attachment 15-6) has been used for disposal of PEP materials which do not detonate. Water slurry of the explosive or propellant is prepared first. Incineration of such a slurry has been found to be relatively safe. No. 2 fuel oil is used as auxiliary fuel with incinerator fired to 1,600°F. The operating control station is located underground at some distance from the kiln and feed preparation area.

A rotary furnace is similar to the kiln, except that a heavy steel drum is provided and the refractory lining is omitted, because it cannot withstand the detonation of even small-caliber ordnance. Control of emissions may be achieved with both of these devices, but is not always practiced.

Fluidized-bed incineration (Attachment 15-7) is another method for munitions disposal. A novel feature of this system is that very low levels of NO_X emissions are possible by using less than stoichiometric air (about 60% of theoretical) for fluidization where most of the combustion takes place. The remainder of the theoretical air, along with approximately 20% excess, is introduced near the top of the bed (10, 11).

Very little information is available on the pollutants arising from PEP incineration. Small arms ammunition and pryotechnic items are expected to give off gases, metallic fumes, vapors, and particulates comprised of metals and metallic compounds. Carbon monoxide and nitrogen oxides are the most objectionable of the gases, while combined or elemental forms of cadmium, lead, chromium, mercury, silver, and antimony are the most objectionable of the particulate matter.

Summary

Incineration appears to be a serious contender as a means of disposing of hazardous waste materials. There are no universally applicable incineration methods available for this purpose, however. Careful attention must be paid to the physical and chemical properties of the specific waste streams, as well as their combustion products. Rotary kilns (cement kilns) may be used to dispose of toxic chemical wastes because their temperatures are in excess of 2,500°F and they have long residence times. Gas cleaning equipment must be added where gaseous products are not suitable for direct discharge to the atmosphere. Safe and environmentally-acceptable disposal of solid residues (ash) cannot be overlooked.

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9. "Laboratory Evaluation of High-Temperature Destruction of Polychlorinated Biphenyls and Related Compounds," Report No. EPA-600/2-77-228 (December 1977).
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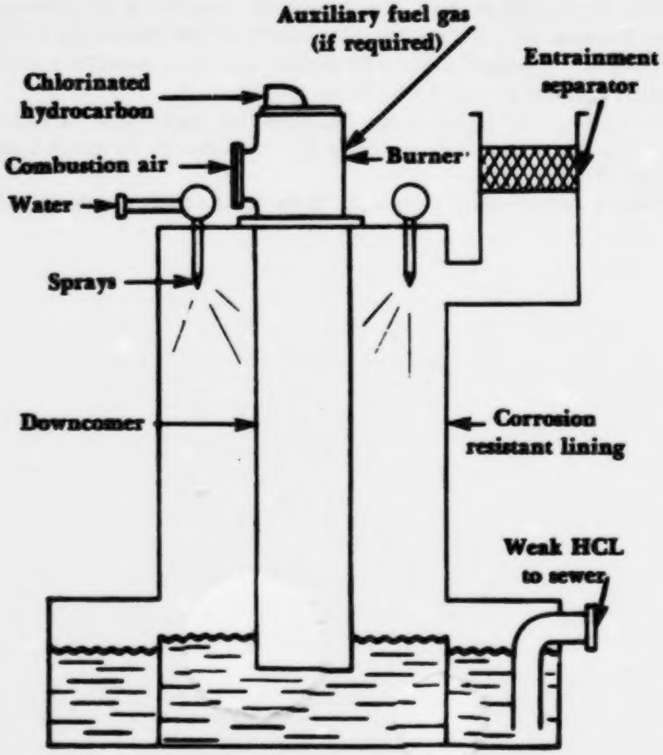
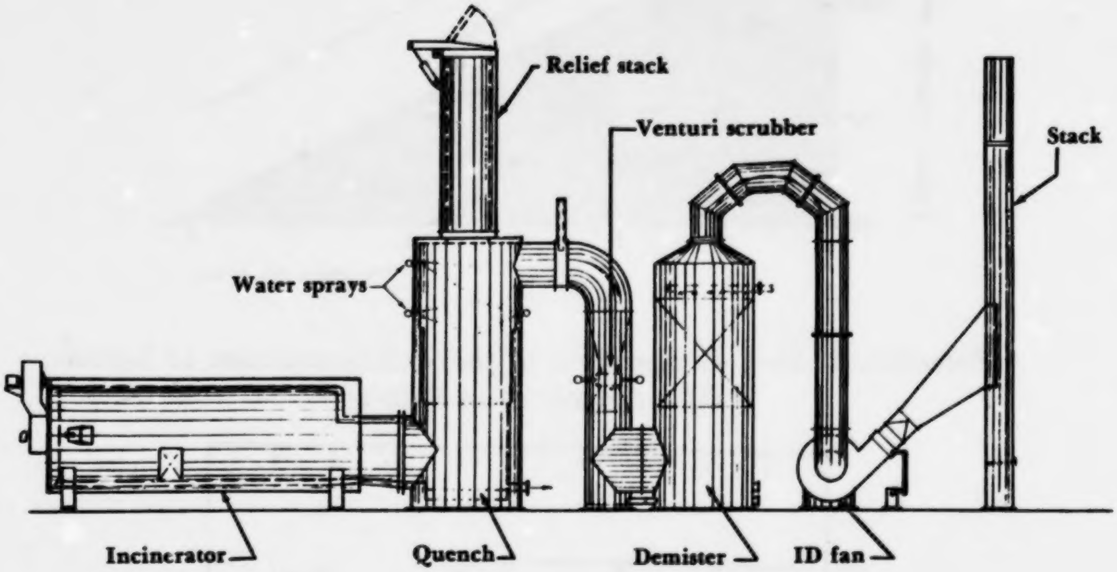
11. Kalfadelis, C. D., "Development of a Fluidized Bed Incinerator for Explosives and Propellants," Esso Research and Engineering Co., Government Research Laboratory Report (October 1973).
12. "Liquid Waste Incinerator," Bulletin STD IN-72-1C, C&H Combustion Co., Troy Michigan.

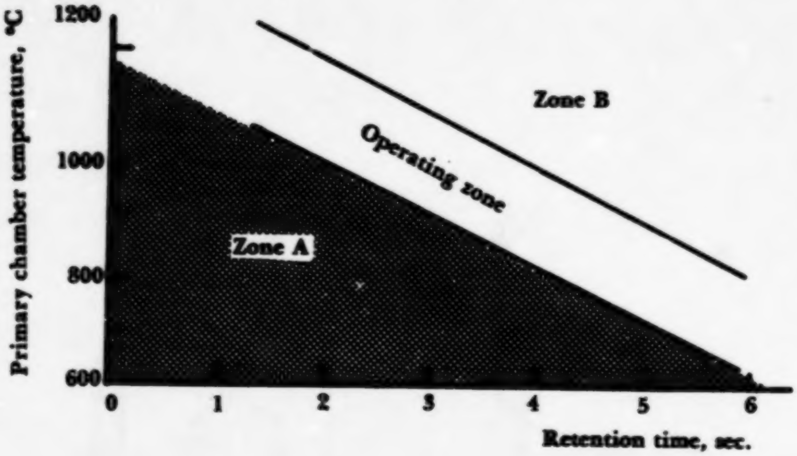
Attachment 15-1. Submerged combustion incinerator[3]


Auxiliary fuel gas (if required)
Entrainment separator
Chlorinated hydrocarbon
Burner
Combustion air
Water
Sprays
Downcomer
Corrosion resistant lining
Weak HCL to sewer

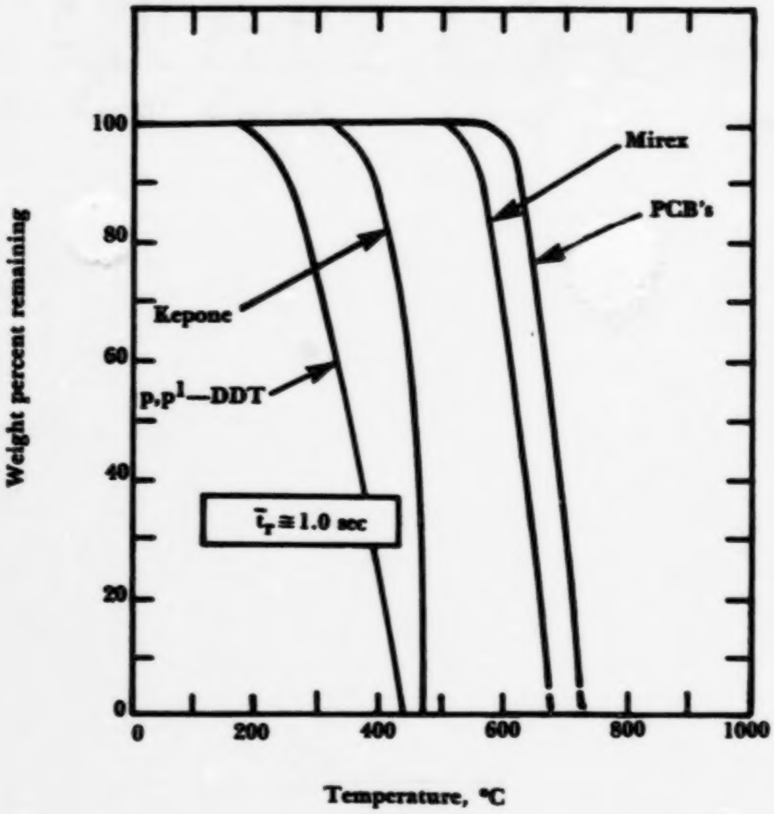
Attachment 15-2. Liquid waste incinerator[12]


Relief stack
Venturi scrubber
Stack
Water sprays
Incinerator
Quench
Demister
ID fan

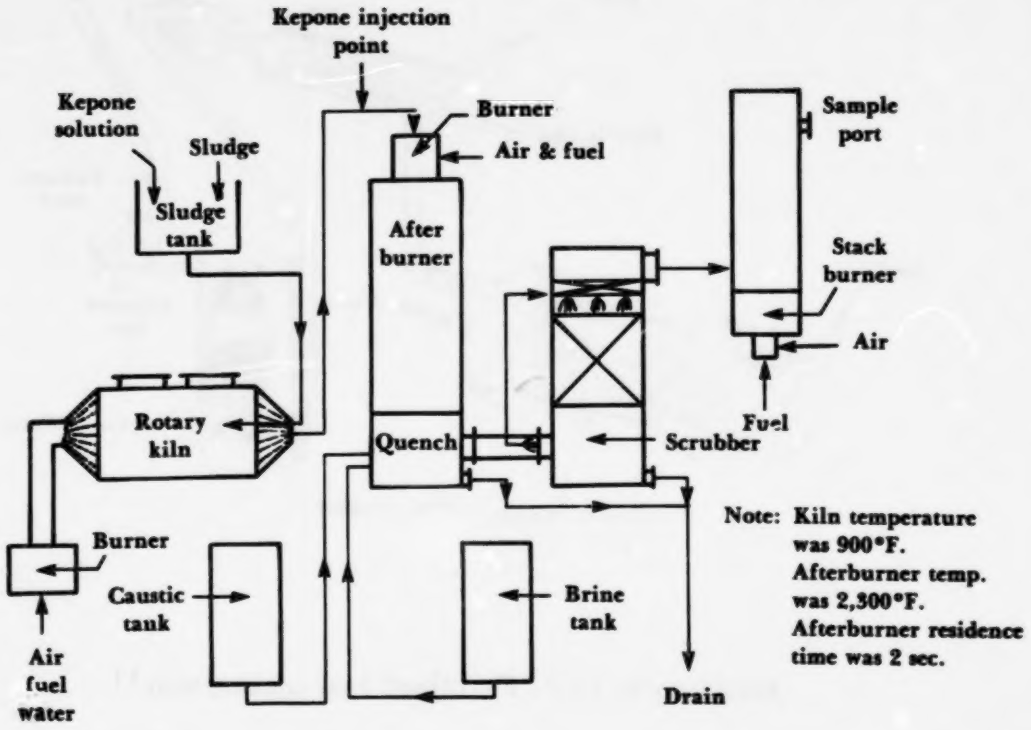
Attachment 15-3. Thermal destruction zones for various pesticides[5]



Attachment 15-4. Comparison of thermal destruction of kepone, DDT, Mirex, and PCB's[7,9]

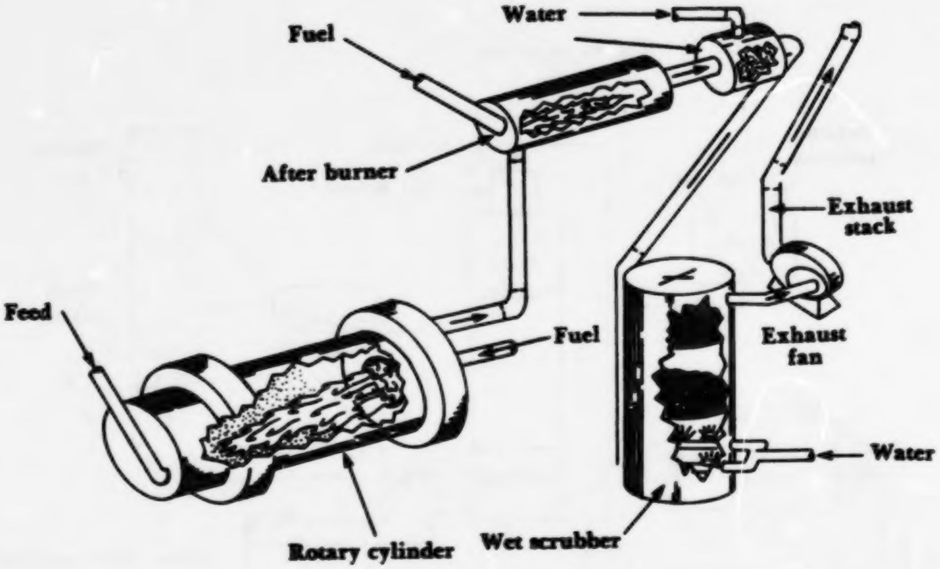


Attachment 15-5. Kepone incineration test system[7]

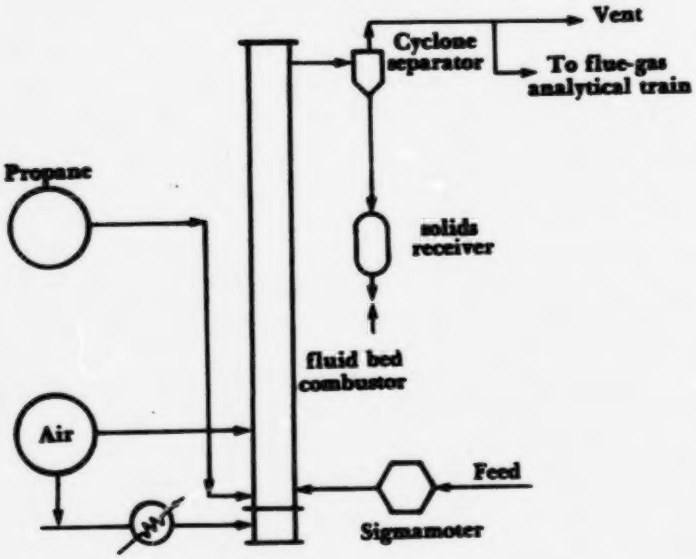

Kepone injection point
Kepone solution
Sludge
Sludge tank
Burner
Air & fuel
After burner
Sample port
Stack burner
Air
Fuel
Rotary kiln
Quench
Scrubber
Burner
Caustic tank
Brine tank
Air fuel water
Drain

Note: Kiln temperature was 900°F. Afterburner temp. was 2,300°F. Afterburner residence time was 2 sec.

Attachment 15-6. Rotary kiln incinerator


Water
Fuel
After burner
Exhaust stack
Feed
Fuel
Exhaust fan
Water
Rotary cylinder
Wet scrubber

Attachment 15-7. Fluidized bed incinerator[11]


Vent
Cyclone separator
To flue-gas analytical train
Propane
solids receiver
fluid bed combustor
Air
Feed
Sigmamoter

Chapter 16

NO_X Control Theory

Background

Emission of nitrogen oxides has been a major air pollution concern since the early 1950s when Professor A. J. Haagen-Smit presented a theory of photochemical smog (1). Although the photochemical reactions are not simple, Professor Haagen-Smit was able to demonstrate that the conditions necessary for smog to develop included bright sunshine into an unventilated region containing nitrogen oxides and hydrocarbon contaminants in the air.

Photochemistry is the study of chemical reactions in the ambient air which are influenced by the sun, air pollution sources, and meteorology. Attachment 16-1 illustrates the transient behavior of measurable gases in the Los Angeles air during a day having smog (2). One could predicts the changes of air pollution emissions and of solar intensity associated with the time of day. Photochemists have performed many smog chamber experiments (see Attachment 16-2) which have helped to refine their theories and have led them to some important conclusions.

A brief and oversimplified set of photochemical equations for atmospheric smog is presented in the Attachment 16-3. Note that in the first equation a high-energy photon of solar energy is absorbed by NO_2 causing dissociation into NO and O (atomic oxygen). The formation of ozone and other unstable, radical products give rise to the highly reactive, oxidant character of smog.

Emissions of NO_X require control because of photochemical participation in producing oxidants. Although very high concentrations of NO_X may be directly hazardous inside certain industrial facilities, ambient levels are seldom within 5% of the direct health hazard threshold limit. Ambient levels are of concern because of photochemical involvement.

Nitrogen oxides are produced by natural sources (volcanoes and forest fires), as well as by man-made sources. Of the man-made NO_X slightly more than half is from mobile, vehicular sources, and slightly less than half is from stationary sources.

The distribution of NO_X emissions from various stationary sources is illustrated in Attachment 16-4. Utility boilers account for 42%, internal combustion engines provide 22%, industrial boilers contribute 18%, and space heating is responsible for 9%.

Projections of future NO_X emissions are dependent upon the future energy supply, as well as the amount of NO_X emission control which will be applied in the future. Attachment 16-5 provides a set of projections which does not assume considerably stricter NO_X controls in the future. Because of the potential growth in NO_X emissions and the resulting photochemical smog (ozone), NO_X control is becoming a major regulatory concern.

NO_X emission factors for a large number of fuel and combustion equipment combinations are tabulated in Attachment 16-6.

NO_x Formation

The dominant oxide of nitrogen which is formed in combustion processes is NO. The NO will oxidize to NO_2 fairly slowly in ambient air, with only 5% typically being oxidized to NO_2 before leaving the stack (except for gas turbine and diesel engines). Other oxides of nitrogen, such as N_2O, nitrous oxide; N_2O_3, nitrogen trioxide; and N_2O_5, nitrogen pentoxide, are of minor consequence. All the nitrogen oxides, when referred to as a group, are called NO_x.

Emissions of NO_x arise from two different methods of formation during combustion. Thermal fixation of nitrogen in the combustion air produces the so-called "thermal NO_x." The NO_x produced by oxidation of the nitrogen found in the chemical composition of the fuel is called "fuel NO_x."

Formation of "Thermal NO_x"

When ambient air is heated in a combustion chamber to a temperature above 2800°F, part of the nitrogen and oxygen will combine to form NO. The classical "Zeldovich" chemical model for NO formation assumes high temperature dissociation of oxygen molecules:

$$O_2 \rightleftharpoons 2O$$

and nitrogen reactions:

$$O + N_2 \rightleftharpoons NO + N$$
$$N + O_2 \rightleftharpoons NO + O.$$

A simplified model used for illustrative purposes is:

$$N_2 + O_2 \underset{K_R}{\overset{K_F}{\rightleftharpoons}} 2NO,$$

Where the NO formation is endothermic, i.e., energy is required rather than produced. This simplified model provides the following equation for the rate of production of NO:

$$\frac{d(NO)}{dt} = K_F(N_2)(O_2) - K_R(NO)^2,$$

where (NO), (N_2), and (O_2) represent the respective concentrations at a particular instant of time, and where values of K_F and K_R increase considerably with temperature.

If the appropriate rate equation is set equal to zero, equilibrium values of NO as a function of temperature may be computed. Typical equilibrium values of NO_x concentration as a function of temperature are presented in Attachment 16-7. The calculation required assumed values for K_F and K_R (the forward and reversed reaction rates, which increase greatly with temperature) and also values for the N_2 and O_2 concentrations.

Formation of "Fuel NO_X"

Nitrogen of differing amounts is contained in the chemical composition of fuels. Coal may contain nitrogen from 0.5 to 2.0% by weight, whereas No. 6 fuel oil may contain from 0.1 to 0.5% and No. 2 contains approximately 0.01%.

When fuel is burned, 10 to 60% of the nitrogen may be oxidized to NO (5). This fraction depends on the amount of oxygen available after the fuel molecules decompose. If combustion zone is fuel rich, the fuel molecules may crack and much of nitrogen will form N_2. On the other hand, if combustion zone is lean, that is, oxygen is available, more fuel nitrogen oxides to NO.

High fuel volatility and intensive fuel/air mixing also increase the fuel nitrogen fraction which oxidizes to NO.

Changing fuels can be an effective method for reducing NO_X. For example, one might change from a high nitrogen content No. 6 fuel oil to No. 2 fuel oil. If it is available, one might specify a low-nitrogen content No. 6 fuel oil. The nitrogen content is influenced by refining processes, blending, and the original crude stock.

Changing from coal to oil or oil to gas usually is controlled by factors such as furnace adaptability, fuel availability, and costs. Because of fuel availability, it is expected that more coal rather than less will be used as boiler fuel in the future, so other techniques of fuel NO_X control will be required.

NO_X Control Theory

The three methods for reducing NO_X are to change the fuel, to modify the combustion system, and to treat or clean the flue gas.

Excess air reduction is an obvious combustion modification control technique, as may be seen from the simplified model of "thermal" NO_X formation. Excess air reduction is very effective for "fuel NO_X" because the reduced availability of oxygen encourages fuel nitrogen to form molecular nitrogen (5). Note that the high chemical reactivity of oxygen with fuel assures that most of the theoretical oxygen will react with fuel. It is the excess oxygen which reacts with nitrogen.

Limits on excess oxygen in coal and oil combustion is important, not only for NO_X control, but also to limit the conversion of SO_2 to SO_3. The formation of SO_3 causes dew point and corrosion problems in furnaces. Because of this fact, oil-fired units, which formerly operated with excess air values from 10 to 20% excess air (2 to 4% excess O_2), typically have been modified to operate at 2 to 5% excess air (0.4 to 1% excess O_2). In gas-fired boilers, it appears that a minimum desirable value of excess O_2 exists for many units, as shown in Attachment 16-8. As the excess air is reduced below this minimum, the temperature increases enough to increase the NO_X emissions (5). In coal combustion, burning with very low values of excess oxygen may present operational problems.

NO_X control has been achieved by designing for two-stage combustion, as illustrated in Attachment 16-9. In the first stage fuel-rich combustion occurs with less than stoichiometric oxygen. Energy is transferred to heat exchange surfaces, and the combustion product gases move to the second stage. Excess air is introduced (lean combustion in this stage), so that adequate oxygen is available for complete combustion. NO_X emissions are reduced, partly because NO is not formed when the combustion is rich. The other reason is because of the energy extraction prior to lean combustion, which results in lower peak temperatures than would occur under normal combustion. Two-stage combustion may be applied through use of overfire air ports, as shown in Attachment 16-10, or through burner redesign. In each case the fuel and air delivery to the combustion zone is designed to delay the mixing of the secondary air.

As previously indicated, the other significant fundamental concept in NO_X control is to limit the maximum combustion temperature. This effectively limits the value of the forward reaction rate coefficient, K_F. For temperatures above 2,800°F, the value of K_F is said to essentially double for each additional 70°F temperature increase.

One should note that in most combustion equipment, the combustion reactions occur so quickly that equilibrium behavior associated with a peak temperature is not achieved. Typically, less NO is formed than would be expected for a given peak temperature. However, the combustion gases cool down so rapidly that the NO formed does not dissociate but is said to "freeze" and be emitted with the flue gases.

One method for reducing the maximum combustion temperature is to eliminate the development of "hot spots" in the combustion gases. These are locations where very rapid mixing of fuel and air occur. By slowing the mixing or swirl of gases, a more uniform flame temperature may result and lower NO_X will be formed.

The type of firing design of the furnace also influences the fuel/air mixing, the proximity of the flames to the heat exchange surface, and the influence of combustion energy from one burner on an adjacent burner.

Cyclone furnaces used for coal combustion have the largest uncontrolled NO_X emissions. Front wall (horizontal) and opposed wall furnaces have somewhat less, and tangential-fired furnaces have considerably less emissions, as illustrated in Attachment 16-11.

Flue gas recirculation is a technique for lowering the peak temperature, as illustrated in Attachment 16-12. Flue gas acts as a heat sink. It also acts to slow the rate of combustion, by reducing the frequency of successful oxidation collisions between the fuel and oxygen molecules. Proper heat exchange design is required to prevent a considerable loss of efficiency due to the lower combustion temperatures.

Reducing the rate of combustion by reducing the fuel rate or load also will reduce the peak temperatures and NO_X emissions. The load reduction may be achieved by energy conservation (lower demand) or by installing or using additional combustion units. The effect of load reduction is shown in Attachment 16-13.

Scheduling frequent soot blowing will provide cleaner heat exchange surfaces around the flame and thereby will limit the peak combustion temperature.

Water injection, as shown in Attachment 16-14, is an accepted NO_X control technique for use in stationary gas turbines. Water acts as a heat sink, similar to the water injection which was used in supercharged aircraft engines in the 1940s (to provide controlled combustion with increased power). Water injection in piston engines was terminated with the adoption of tetraethyl-lead as a more convenient heat sink material.

Flue Gas Treatment

Dry flue gas treatment with gases from 100 to 700°F is used widely in Japan for NO_X control in oil and gas furnaces (7). This technique requires a reducing atmosphere (typically with ammonia injection) and a catalyst. Developmental work is underway to apply this concept to the particulate and SO_2-laden gas streams from coal combustion. If ammonia is injected as the combustion gases reach the convection zone of a large boiler, up to 70% NO_X reduction can be demonstrated (5). However, the convection zone temperature must be controlled carefully to around 1,300°F, as illustrated in Attachment 16-15.

Wet flue gas techniques involve a strong oxidant, such as ozone or chlorine dioxide to convert NO to NO_2 and N_2O for subsequent absorption by a scrubbing solution. These scrubbers are operated at 100 to 120°F, the same operating temperature for SO_X scrubbers. This technique is very expensive, because of the cost of chlorine dioxide and ozone, in addition to the cost of disposing of the chlorine containing discharges. However, hope is expressed for the possibility of this technique being effective for controlling NO_X, SO_X, and particulates from coal-fired power plants.

Fluidized Bed Combustion

A non-traditional combustion scheme is that of fluidized bed combustion. It appears promising for future low NO_X applications, mainly because combustion occurs with low temperatures and because SO_X control can be achieved also (5). Various fluidized bed applications are being demonstrated, such as for:

1. Solid waste and sewage sludge incineration;
2. Hog fuel combustion;
3. Coal in a utility boiler (30 MW electricity by Monongahela Power Co., Rivesville, West Virginia); and
4. Coal in a similar fired industrial boiler (100,000 lb. steam/hr. by Georgetown University, Alexandria, VA).

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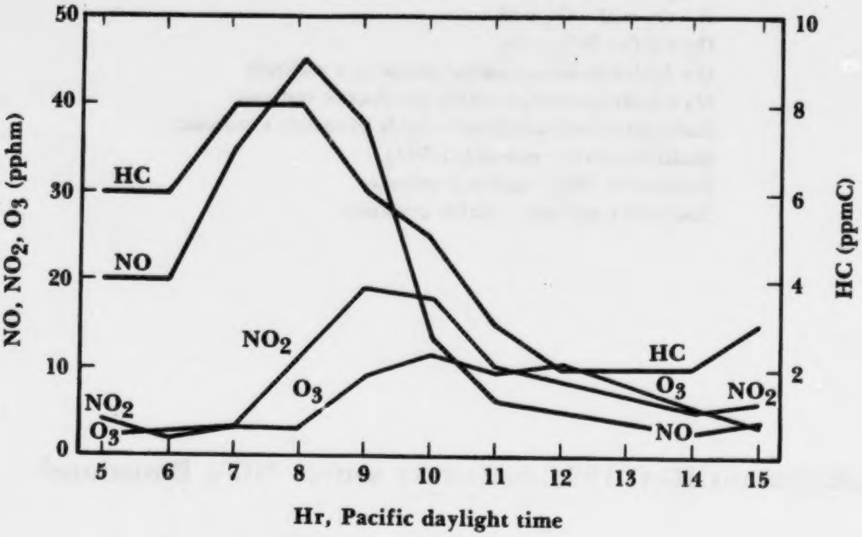
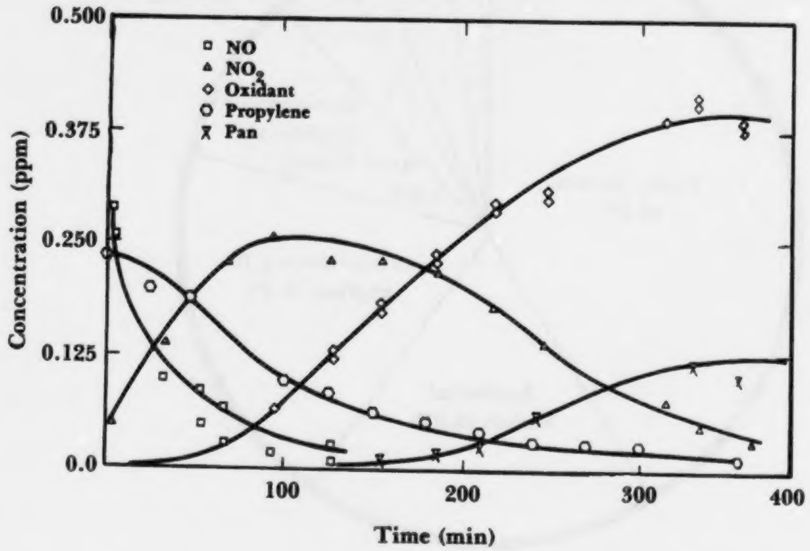
2. Seinfeld, J. H., *Air Pollution, Physical and Chemical Fundamentals*, McGraw-Hill Book Co., New York (1975).
3. Strauss, Werner, *Air Pollution Control*, Part I, Wiley Interscience, New York (1971).
4. Wark, K., and Werner, C. F., *Air Pollution, Its Origin and Control*, Harper and Row, Publishers, New York (1976).
5. "Control Techniques for Nitrogen Oxide Emissions from Stationary Sources," Second Edition, EPA-450/1-78-001, U.S. Environmental Protection Agency (January 1978).
6. "Reference Guideline for Industrial Boiler Manufacturers to Control Pollution with Combustion Modification," EPA-600/8-77-003b, Industrial Environmental Research Laboratory, U. S. Environmental Protection Agency (January 1977).
7. Muzio, L. J., et al., "Gas Phase Decomposition of Nitric Oxide in Combustion Products," paper No. P-158, 16th Symposium (International) on Combustion, Cambridge, Mass. (August 15-21, 1976).

8. **Sensenbaugh, J. D., "Formation and Control of Oxides of Nitrogen in Combustion Processes," Unpublished paper, Combustion Engineering, Inc., Windsor, Conn. (1966).**
9. **Muzio, L. J., Arend, J. K., and Teixeira, D. P., "Gas Phase Decomposition of NO_X in Combustion Products," Paper No. P-158, 16th International Symposium on Combustion, Cambridge, MA (August 15, 1976).**
10. **"Electric Utility Steam Generating Units—Background Information for Proposed NO_X Emission Standards," EPA-450/2-78-005a, Office of Air Quality Planning and Standards, U.S.E.P.A., Research Triangle Park, NC (July 1978).**

Attachment 16-1. Concentrations of total hydrocarbons, NO, NO_2, and O_3 at Downtown Los Angeles (Sept. 29, 1969)[2]



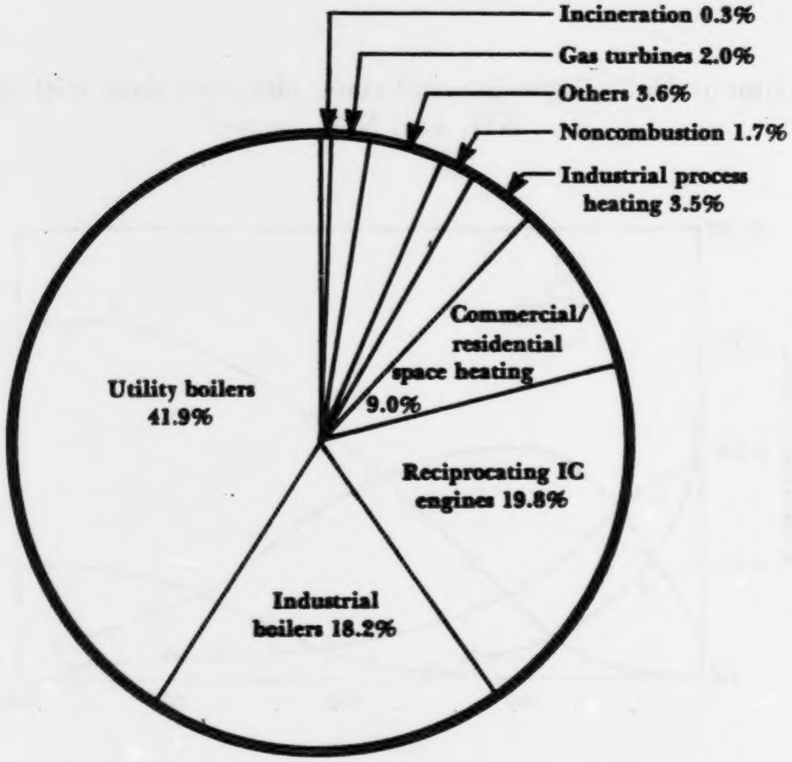
Attachment 16-2. Experimental smog chamber data with propylene, NO, and NO_2 in air[2]



Attachment 16-3. Generalized photochemical reaction equations[4]

$NO_2 + h\nu \rightarrow NO + O$
$O + O_2 + M \rightarrow O_3 + M$
$O_3 + NO \rightarrow NO_2 + O_2$
$O + \text{hydrocarbons} \rightarrow \text{stable products} + \text{radicals}$
$O_3 + \text{hydrocarbons} \rightarrow \text{stable products} + \text{radicals}$
$\text{Radicals} + \text{hydrocarbons} \rightarrow \text{stable products} + \text{radicals}$
$\text{Radicals} + NO \rightarrow \text{radicals} + NO_2$
$\text{Radicals} + NO_2 \rightarrow \text{stable products}$
$\text{Radicals} + \text{radicals} \rightarrow \text{stable products}$

Attachment 16-4. 1974 stationary source NO_X Emissions[5]



Attachment 16-5. Annual NO_X emissions projections[5]

Source category	NO_X emissions (10^6 tons)				
	1972	1980	1985	1990	2000
Stationary fuel combustion	12.27	15.96 (17.12)[a]	16.82 (21.43)	18.46 (27.14)	21.74 (44.46)
Electric generation	5.94	8.16 (9.32)	8.20 (12.81)	8.88 (17.56)	10.24 (32.96)
Industrial	5.39	6.73	7.46	8.31	10.01
Commercial-institutional	0.65	0.76	0.84	0.93	1.11
Residential	0.29	0.31	0.32	0.34	0.38
Industrial process losses[b]	0.70	0.95	1.14	1.38	1.85
Solid waste disposal	0.18	0.22	0.25	0.28	0.34
Miscellaneous	0.59	0.74	0.87	1.02	1.32
TOTAL	13.74	17.87 (19.03)	19.08 (23.69)	21.14 (29.82)	25.25 (47.97)

[a] NO_X emissions for no new nuclear power plants after 1975 are given in parentheses.

Attachment 16-6. Emission factors for utility boilers, 1974[5]

Equipment type	Firing type	Fuel	Fuel type	Fuel usage 10^{12} Btu	Emission factors lb $NO_2/10^6$ Btu
Field-erected watertube boilers	Tangential firing	Coal	Bituminous	4140.66	0.64
			Lignite	41.72	0.64
		Oil	Distillate	45.23	0.357
			Residual	1086.57	0.357
		Gas	–	867.55	0.30
	Horizontally opposed wall firing	Coal, dry bottom	Bituminous	1229.22	0.75
			Lignite	11.97	0.88
		Coal, wet bottom	Bituminous	548.06	1.25
			Lignite	16.12	0.88
		Oil	Distillate	33.08	0.75
			Residual	792.40	0.75
		Gas	–	1378.23	0.70
	Front wall firing	Coal, dry bottom	Bituminous	1229.22	0.75
			Lignite	11.97	0.88
		Coal, wet bottom	Bituminous	540.23	1.25
			Lignite	14.32	0.88
		Oil	Distillate	33.08	0.75
			Residual	792.40	0.75
		Gas	–	94.22	0.70
	Vertical firing	Coal, dry bottom	Anthracite	29.86	0.75
			Bituminous	378.83	0.75
			Lignite	2.99	0.75
	Cyclone	Coal, wet bottom	Bituminous	1020.62	1.30
			Lignite	12.64	0.88
		Oil	Distillate	2.92	0.75
			Residual	55.53	0.75
Field-erected watertube boiler Stoker	Spreader	Coal	–	131.98	0.57
	Underfeed	Coal	–	56.60	0.57

Attachment 16-6 (cont'd). Emission factors for industrial boilers, 1974[5]

Equipment type	Firing type	Fuel	Fuel type	Fuel usage 10^{12} Btu	Emission factor lb $NO_2/10^6$ Btu
Field-erected watertube boilers $>100 \times 10^6$ Btu/hr	Tangential firing	Coal	–	141.32	0.640
		Oil	Residual	427.56	0.357
		Gas	Natural	391.47	0.301
			Process	54.99	0.230
	Horizontally opposed wall firing	Coal, dry bottom	–	42.40	0.750
		Coal, wet bottom	–	8.48	1.250
		Oil	Residual	414.67	0.573
		Gas	Natural	462.61	0.301
			Process	123.74	0.230
	Front-wall firing	Coal, dry bottom	–	42.40	0.750
		Coal, wet bottom	–	8.48	1.250
		Oil	Residual	414.67	0.573
		Gas	Natural	313.64	0.301
			Process	95.92	0.230
	Vertical firing	Coal, dry bottom	–	9.36	0.750
	Cyclone	Coal, wet bottom	–	61.83	1.660
		Oil	Residual	35.21	0.573
Field-erected watertube boilers $10\text{-}100 \times 10^6$ Btu/hr	Wall firing	Oil	Distillate	58.61	0.150
			Residual	292.77	0.429
		Gas	Natural	806.41	0.230
			Process	37.14	0.230
Field-erected watertube boilers stokers	Spreader	Coal	–	768.80	0.417
	Underfeed	Coal	–	435.28	0.417
	Overfeed	Coal	–	209.16	0.625
	General, not classified	Coal	–	101.75	0.417

Attachment 16-6 (cont'd). Emission factors for industrial boilers, 1974[5]

Equipment type	Firing type	Fuel	Fuel type	Fuel usage 10^{12} Btu	Emission factor lb $NO_2/10^6$ Btu
Packaged watertube bent tube straight tube (obsolete)	Wall firing	Coal	–	42.40	0.750
		Oil	Distillate	146.81	0.157
			Residual	788.44	0.429
		Gas	Natural	2535.75	0.230
			Process	132.43	0.230
Packaged watertube stoker	Spreader	Coal	–	363.91	0.417
	Underfeed	Coal	–	567.60	0.417
	Overfeed	Coal	–	90.45	0.625
	General, not classified	Coal	–	59.36	0.417
Packaged firetube scotch	Wall firing	Oil	Distillate	146.81	0.157
			Residual	735.15	0.429
		Gas	Natural	802.60	0.230
			Process	18.96	0.230
Packaged firetube firebox	Wall firing	Oil	Distillate	56.45	0.157
			Residual	290.32	0.429
		Gas	Natural	693.23	0.230
			Process	18.96	0.230
Packaged firetube firebox stoker	Spreader	Coal	–	16.96	0.417
	Underfeed	Coal	–	84.80	0.417
	Overfeed	Coal	–	11.31	0.625
Packaged firetube HRT	Wall firing	Oil	Distillate	28.23	0.157
			Residual	152.79	0.429
		Gas	–	364.82	0.230
Packaged firetube HRT stoker	Spreader	Coal	–	8.48	0.417
	Underfeed	Coal	–	42.40	0.417
	Overfeed	Coal	–	5.65	0.625

Attachment 16-6 (cont'd). Emission factors for commercial boilers[5]

Equipment type	Firing type	Fuel	Fuel type	Fuel usage 10^{12} Btu	Emission factor lb $NO_2/10^6$ Btu
Packaged firetube scotch	Wall firing	Oil	Distillate	516.65	0.157
			Residual	516.65	0.430
		Gas	–	655.41	0.230
Packaged firetube firebox	Wall firing	Oil	Distillate	516.65	0.157
			Residual	516.65	0.430
		Gas	–	655.41	0.230
Packaged firetube firebox, stoker	All categories	Coal	–	165.72	0.417
Packaged firetube HRT	Wall firing	Oil	Distillate	258.33	0.157
			Residual	258.33	0.430
		Gas	–	327.71	0.230
Packaged firetube HRT, stoker	All categories	Coal	–	82.86	0.417
Packaged firetube, general, not classified	Wall firing	Oil	Distillate	86.91	0.157
			Residual	79.91	0.430
		Gas	–	109.24	0.103
	Stoker and handfire	Coal	–	18.41	0.25
Packaged cast iron boilers	Wall firing	Oil	Distillate	258.33	0.157
			Residual	258.33	0.430
		Gas	–	409.63	0.120
Packaged watertube coil	Wall firing	Oil	Distillate	28.01	0.157
			Residual	34.28	0.430
		Gas	–	43.69	0.103
Packaged watertube firebox	Wall firing	Oil	Distillate	16.85	0.157
			Residual	22.84	0.430
		Gas	–	18.21	0.103
Packaged watertube general, not classified	Wall firing	Oil	Distillate	28.01	0.157
			Residual	34.28	0.430
		Gas	–	43.69	0.103

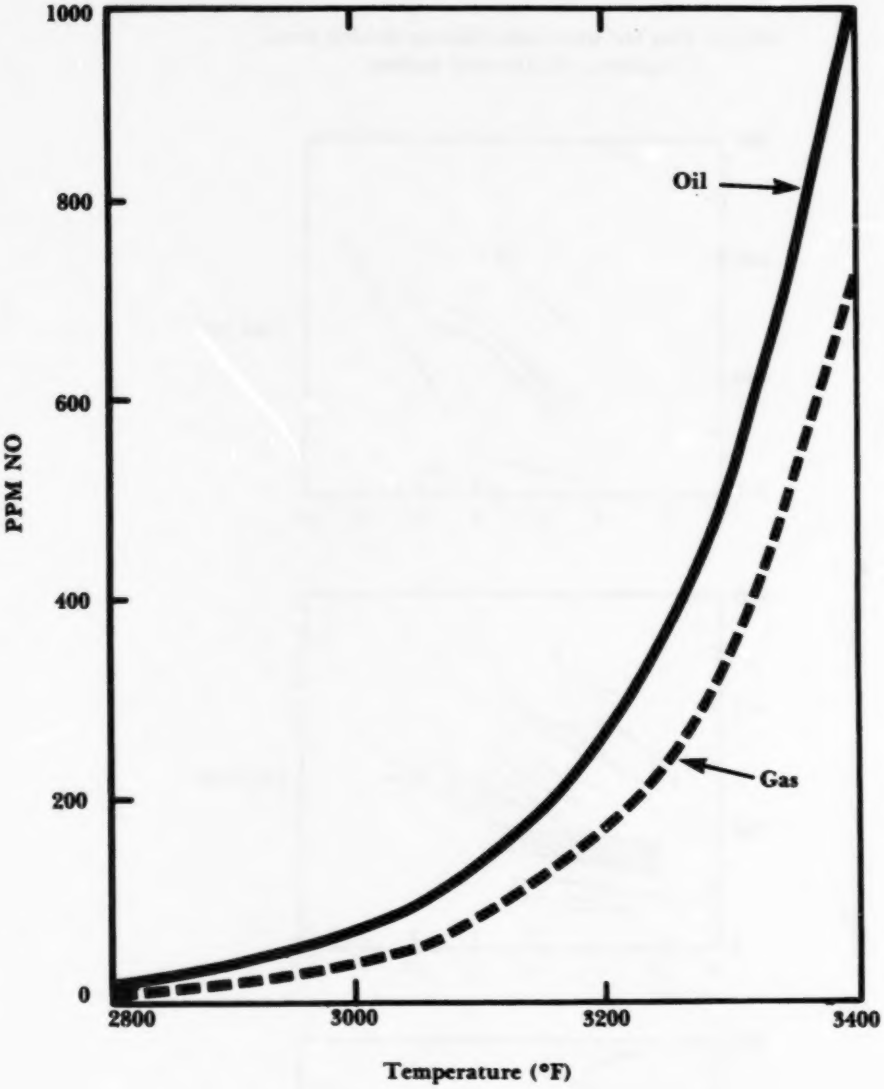
Attachment 16-6 (cont'd). Emission factors for residential units. 1974[5]

Equipment type	Firing type	Fuel	Fuel type	Fuel usage 10^{12} Btu	Emission factor lb $NO_2/10^6$ Btu
Steam or hot water heaters	Single burner	Oil	Distillate	1207.49	0.128
		Gas	–	1000.11	0.082
Hot air furnaces	Single burner	Oil	Distillate	1331.93	0.128
		Gas	–	2929.80	0.082
Floor, wall, or pipeless heaters	Single burner	Oil	Distillate	199.11	0.128
		Gas	–	675.04	0.082
Room heater with flue	Single burner	Oil	Distillate	298.67	0.128
		Gas	–	700.06	0.082
Room heater without flue	Single burner	Oil	Distillate	190.79	0.082

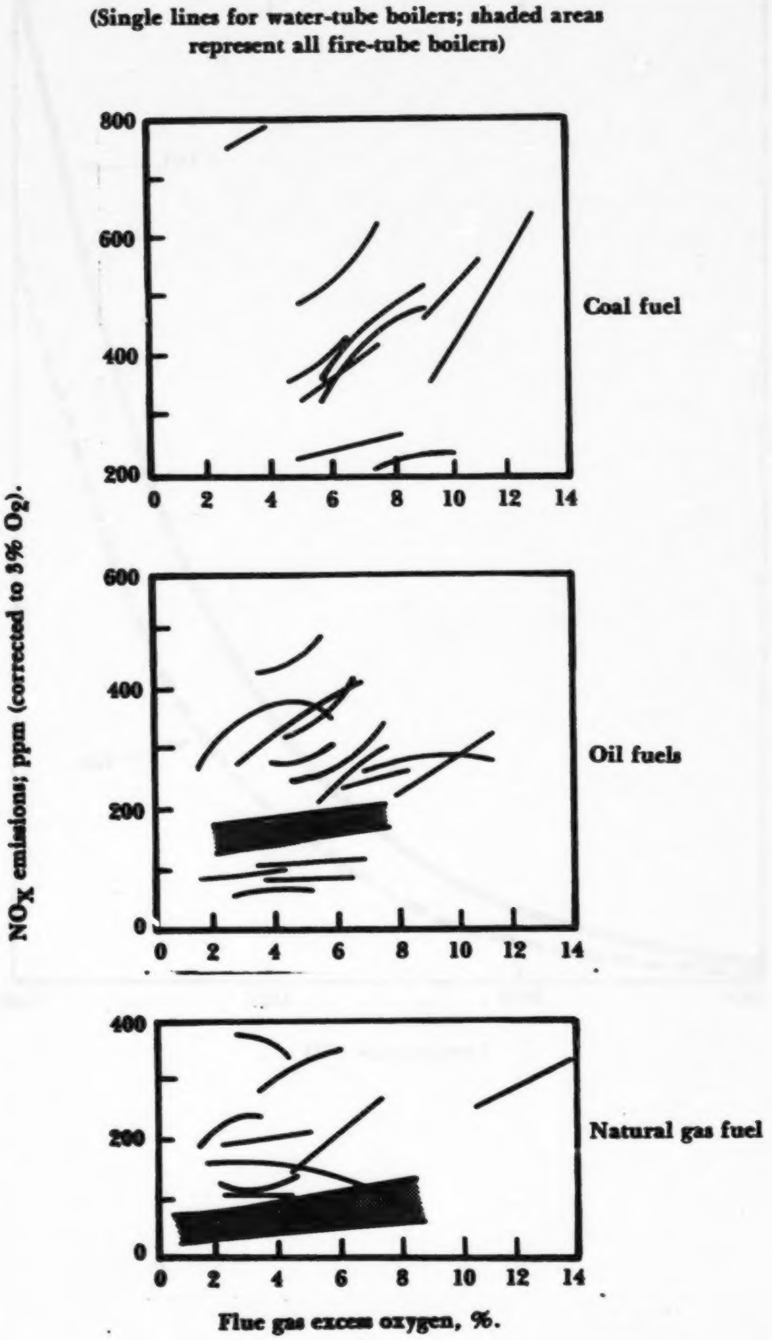
Attachment 16-6 (cont'd). Emission factors for various engines, 1974[5]

Equipment type	Firing type	Fuel	Fuel usage 10^{12} Btu	Emission factor lb $NO_2/10^6$ Btu
Reciprocating engines	Spark ignition	Gas	1007.73	4.40
	Diesel >500 hp	Oil	63.76	4.16
	Diesel <500 hp	Oil	139.30	3.41
		Dual	51.01	2.91
Gas turbines		Gas	608.86	0.45
		Oil	285.64	0.85

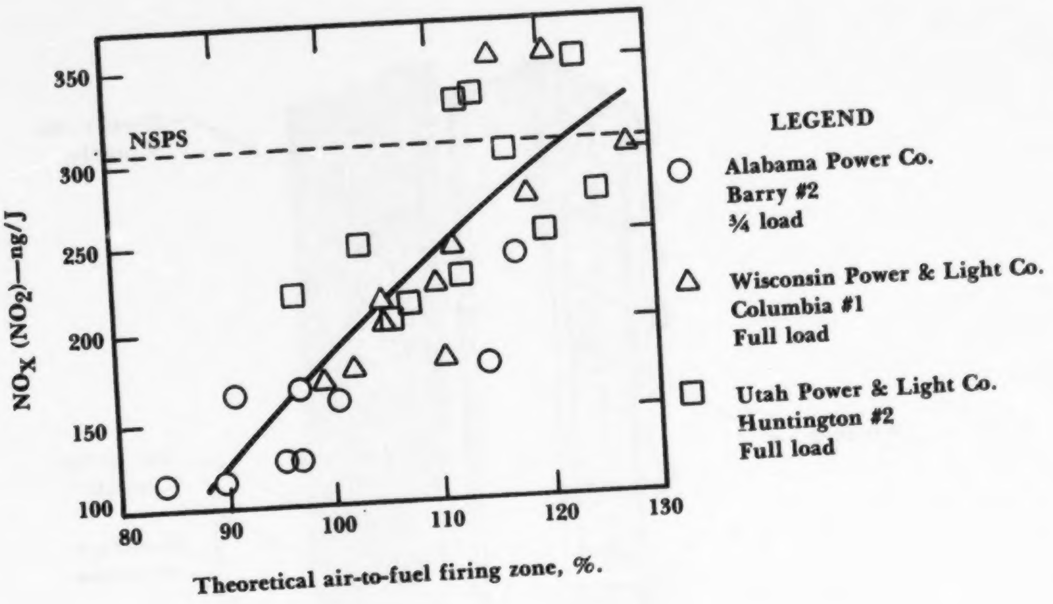
Attachment 16-7. Theoretical curves of NO concentration vs. temperature for oil and gas firing[8]



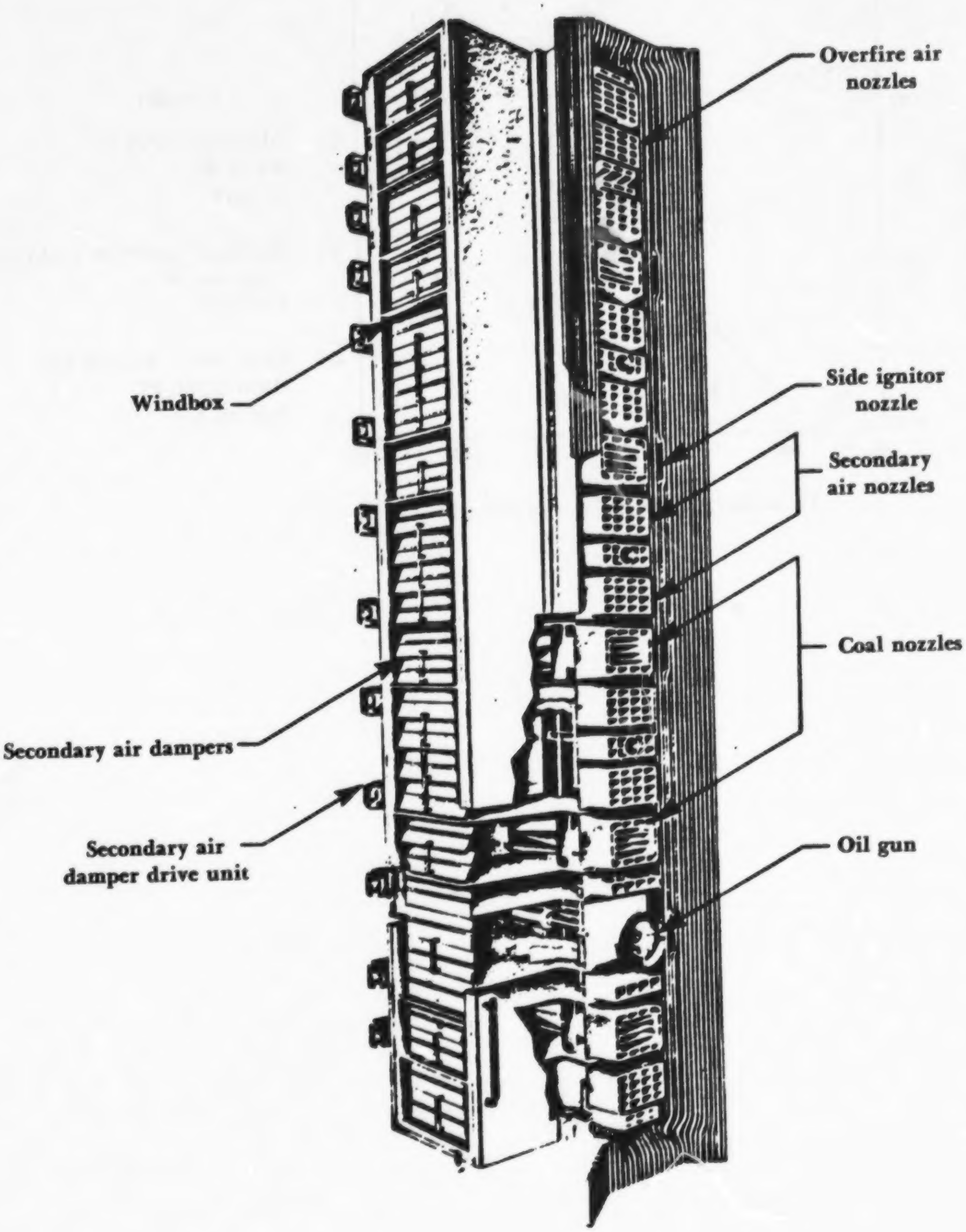
Attachment 16-8. Effect of excess oxygen, fuel, and equipment on nitrogen oxides emissions[7]



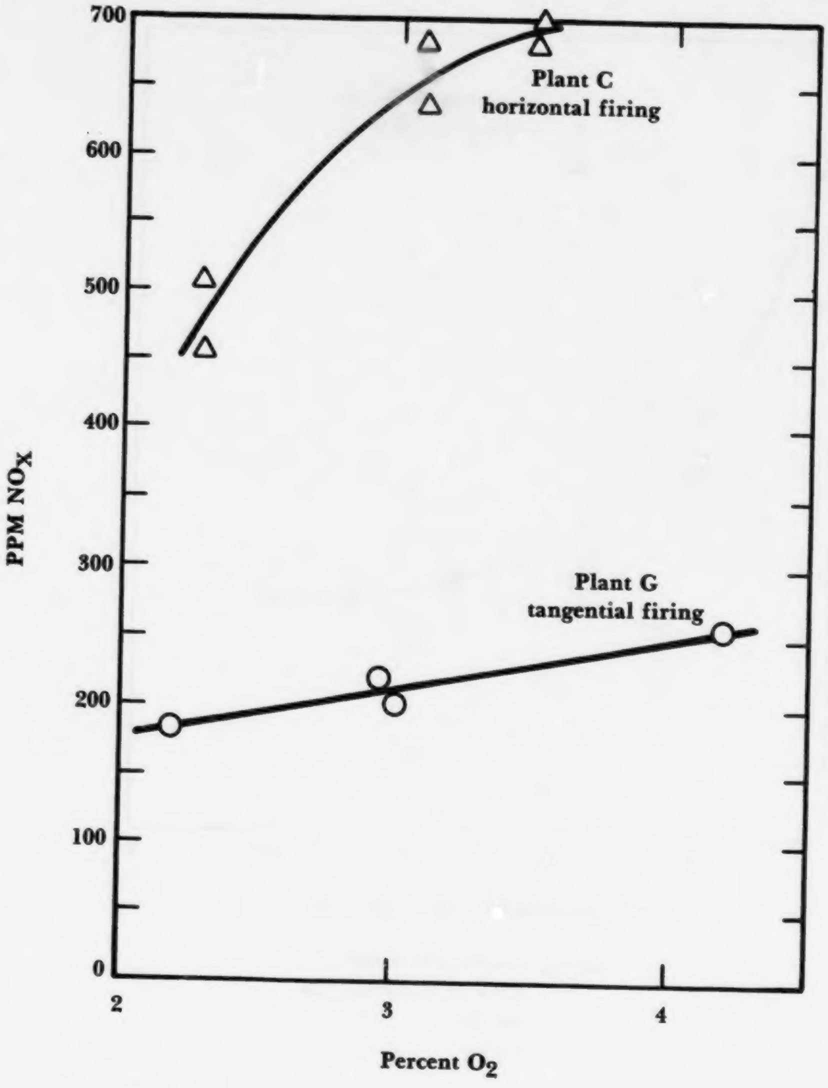
Attachment 16-9. NO_X vs. theoretical air, with overfire air[5]



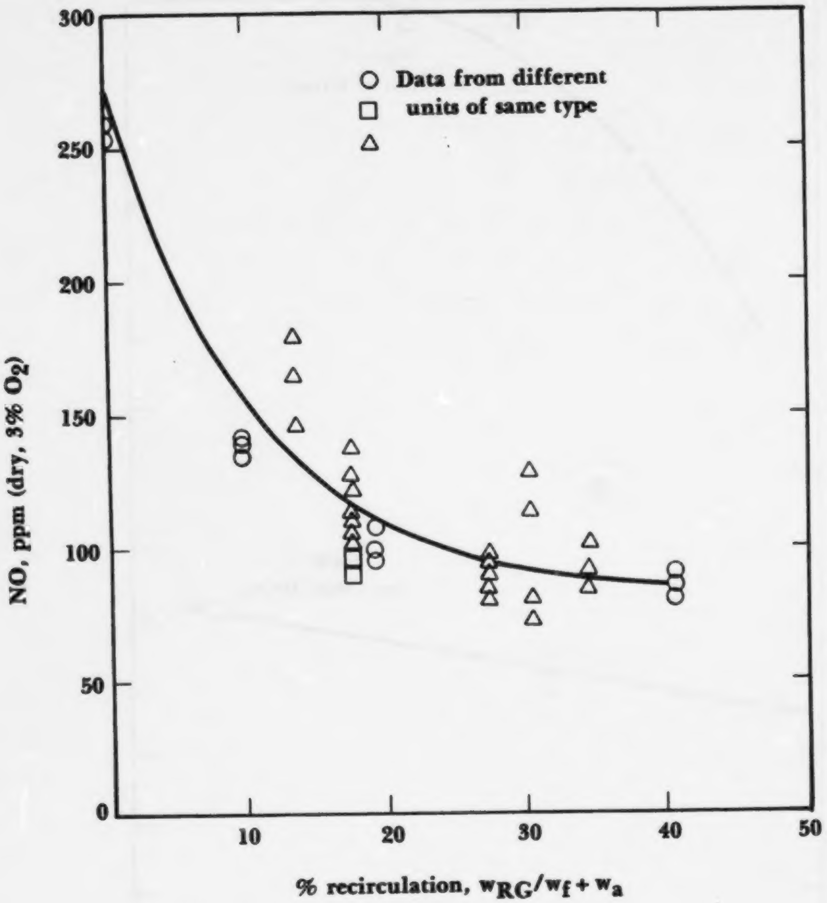
Attachment 16-10. Corner windbox showing overfire air two-stage combustion system[5]


Overfire air nozzles
Side ignitor nozzle
Secondary air nozzles
Windbox
Coal nozzles
Secondary air dampers
Secondary air damper drive unit
Oil gun

Attachment 16-11. NO_X emissions from horizontal and tangential fired oil boilers[8]



Attachment 16-12. Effect of FGR on NO emissions from tangentially-fired gas boilers[5].



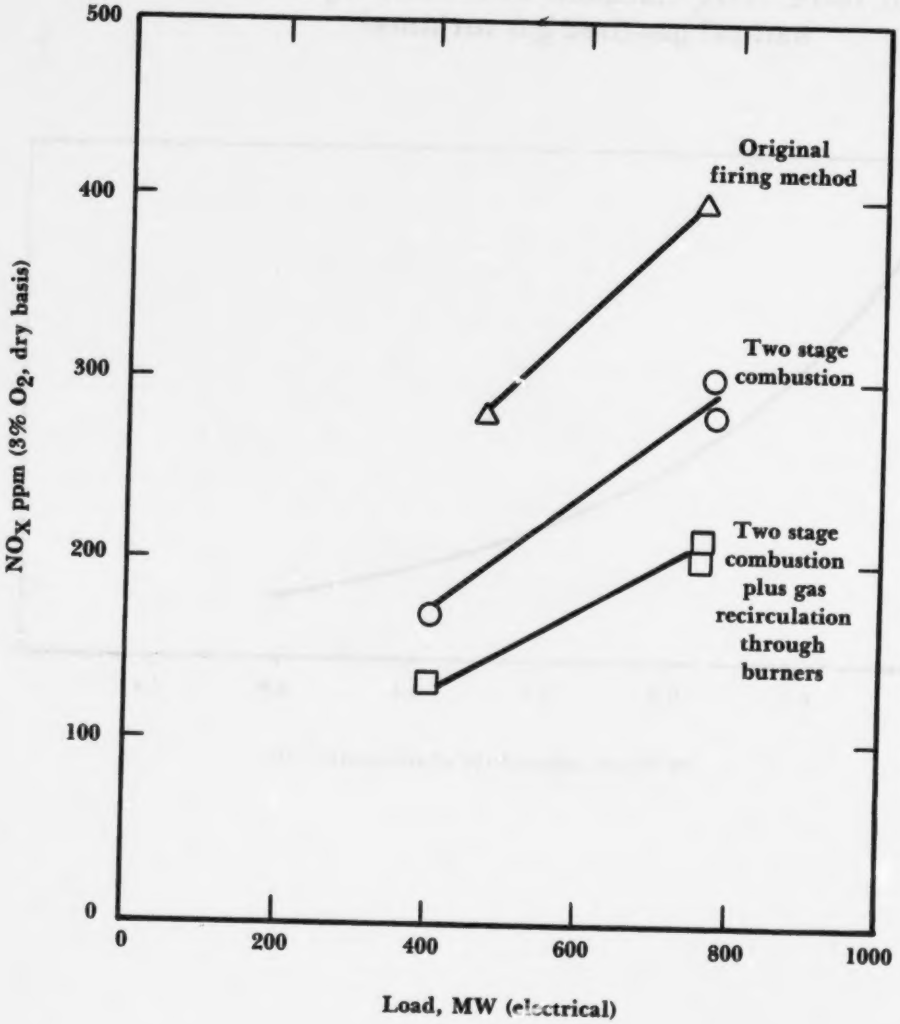
Where, w = mass flowrate

RG = recirculated gas

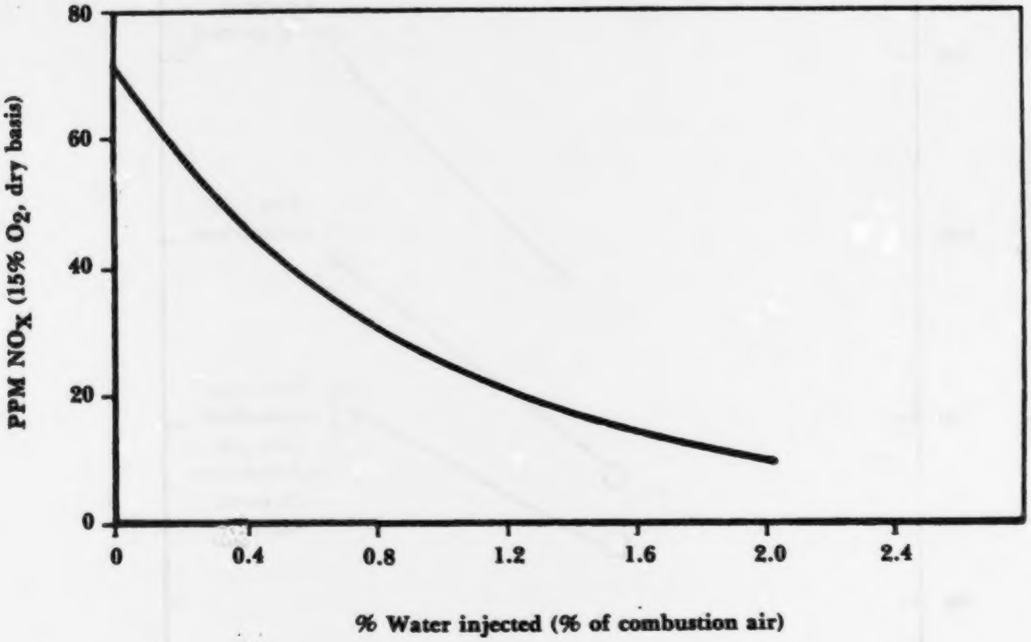
f = fuel

a = air

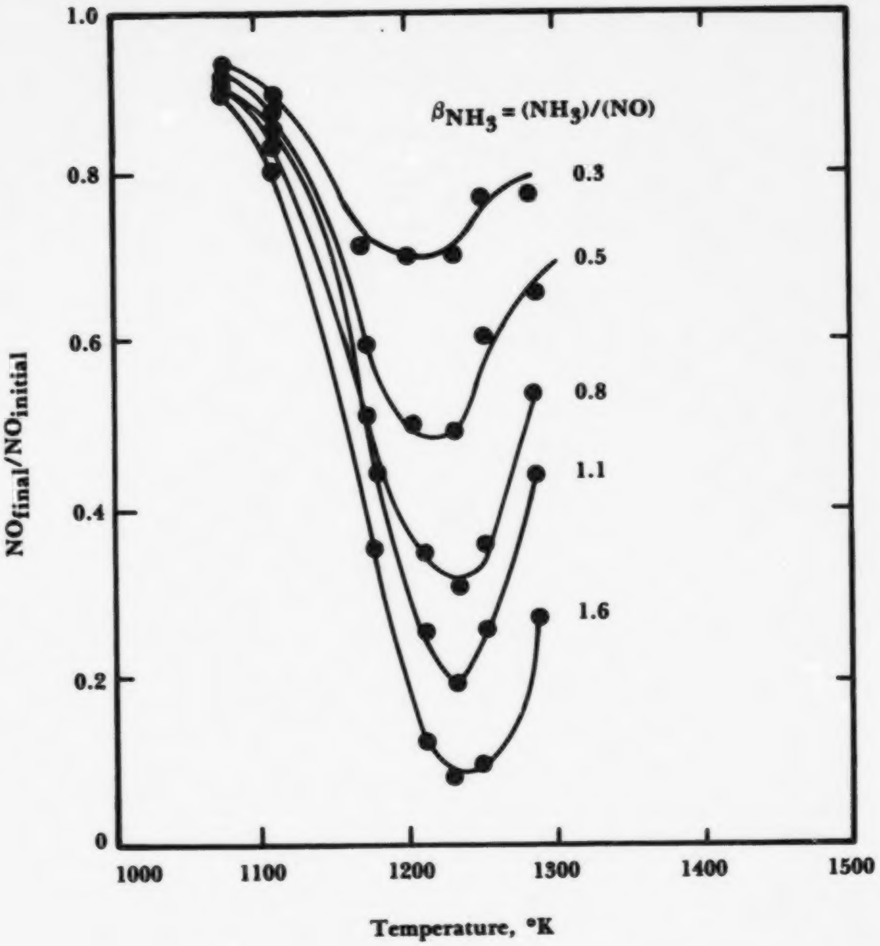
Attachment 16-13. Effects of NO_X control methods, including load reduction for an oil, wall-fired utility boiler[5]



Attachment 16-14. NO_X emissions with water injection rate for natural gas-fired gas turbines[5]



Attachment 16-15. Effect of temperature on reducing NO with ammonia[9]



Chapter 17

Improved Performance by Combustion Modification

INTRODUCTION

Prior to the mid-1960s the main emphasis for preventive maintenance for most combustion equipment was to assure safe operation and to prevent major damage which could result in costly repairs and loss of service. An annual boiler inspection was required typically by the insurance company.

With the enforcement of air pollution emission regulations, preventive maintenance gained importance. Considerably increased fuel costs since the "energy crisis of 1973" have provided an increasing emphasis on conscious maintenance necessary to preserve high boiler efficiencies (1).

Efficiency-related maintenance of combustion equipment is directed toward correcting conditions which may increase fuel utilization. Among these conditions are high stack gas temperatures, elevated combustible content in ash, high excess air, and other factors involving heat loss.

This chapter will describe the maintenance and adjustments recommended by EPA for reducing air pollutants and improving thermal efficiencies for residential, commercial, and industrial combustion units. In addition, examples of the influence of various combustion design modifications for industrial and utility boilers will be discussed.

Residential Oil-Burner Maintenance and Adjustments

Residential and commercial oil combustion units, with proper maintenance and adjustment, can achieve improved thermal efficiency and minimized smoke, particulate, *CO*, and hydrocarbon emissions (2).

Annual maintenance should be performed by a skilled technician. Among the items recommended is the annual nozzle replacement. As the nozzle typically is made of brass, slight wear can cause a change in the spray pattern and droplet formation. Combustion deposits or other foreign materials also will cause poor atomization. The replacement nozzle should be that recommended by the manufacturer. An oversize nozzle could cause short cycling; lower efficiency and higher air pollution emissions would probably result.

Dirt and lint should be cleaned from the blast tube, housing, and blower wheel. If any air leaks into the combustion chamber are found, they should be sealed. The electrodes should be adjusted for proper iginition, and the oil pump pressure should be set to the manufacturer's specifications if necessary.

Following the EPA recommended adjustment procedure, a smoke versus flue gas CO_2 plot for the given installation can be obtained experimentally, using different settings of the air gate (2). Among the equipment required is a draft gauge to be used in adjusting the barometric draft regulator to the manufacturer's recommended value, a Backarach smoke tester, and an Orsat or Fyrite apparatus for measuring CO_2 in the flue gases.

An example of the above-mentioned plot is given in Attachment 17-1. Note the "knee" of the curve is where the smoke number begins to rise sharply. The air setting should be adjusted for a CO_2 level from 0.5 to 1.0% lower than the level at the "knee." This will provide reasonable assurance that the unit can operate properly, without smoke, under normal operational fluctuations of fuel, air pressure, air temperature, etc.

The results of the adjustment should be compared with the appropriate standard values in Attachment 17-2. The smoke level should not be greater than No. 2 and the CO_2 level not less than the table value. Deviation can be caused by air leakage into the combustion chamber, or by poor air-fuel mixing. Changing the nozzle to one with different spray angle and pattern may result in better performance.

Next the stack temperature, under steady operation, should be measured. The net stack temperature can be computed by subtracting the room air temperature from the thermometer reading. This value can be compared with those shown in Attachment 17-3. Excessive stack loss is indicated if the net stack temperature exceeds 400 to 600°F for matched-package units or 600 to 700°F for conversion burners. Stack loss may result from operating the unit at an excessive firing rate which will generate more heat than the heat exchanger can utilize.

Commercial Oil-Fired Boiler Adjustments

The EPA recommended maintenance for commercial oil-fired boilers (3) is almost the same as for residential units. The skilled technician should confirm that the oil temperature or viscosity range is suitable for the installation. Typical viscosity values are given in Attachment 17-4. In some cases, the technician may determine if the combustion is cycling too rapidly for the fuel being burned. For example, No. 6 fuel oil cannot burn completely in a rapidly cycling installation due to the cool condition of the refractory wall. A switch to No. 2 oil usually is suggested.

The recommended adjustment procedure, like that for residential burners, involves taking smoke and CO_2 data for various air settings with the fuel at the full firing rate. A characteristic plot is found in Attachment 17-5. After the "knee" of the curve has been identified, the air setting should be adjusted to where the CO_2 level is about 0.5% lower than the "knee" value.

The smoke level at the above adjustment should be below the "maximum desirable" shown in Attachment 17-6, with a CO_2 level at 12% or higher. If not, it is likely that the atomization and/or the fuel-air mixing are poor. The trouble may be with an improper or dirty nozzle, the atomizing pressure or temperature, or the air handling parts.

For modulating burners, the above procedure should be repeated at low-fire and intermediate-fire settings. Typically, the optimum air setting at low-fire will be at lower CO_2 than at the high-fire condition.

If the boiler is equipped for gas firing, the same procedure should be used. Note, however, that for the same excess air, the CO_2 level will be lower with gas than with oil firing, as illustrated in Attachment 17-7. Also, it is important to check the CO reading. It should be below the recommended 400 ppm as CO can be emitted from gas units even without smoke.

Industrial Boiler Maintenance and Adjustment

Industrial boilers, with proper maintenance and adjustment for operation at lowest practical excess oxygen level, can achieve improved overall thermal efficiency and reduced NO_x emissions.

Thermal efficiency improvement with lowering excess air is shown in Attachment 17-8. The improved efficiency results from the fact that less flue gas is available to carry energy loss out the stack. However, as excess oxygen is reduced in coal and oil-fired industrial units, a "smoke limit" or "minimum O_2 level" is reached where the unit begins to smoke. This is illustrated in Attachment 17-9.

Similarly for a natural-gas fired unit, as excess oxygen is reduced, the CO emissions rise (see Attachment 17-10). Therefore, a "CO limit" or "minimum O_2 level" has been recommended corresponding to 400 ppm CO.

The EPA has published a recommended step-by-step adjustment procedure to provide for the low excess oxygen operation of existing industrial-sized combustion units (4). The main differences between this procedure and those for residential and commercial units has to do with size and equipment features, including the instrumentation available and the sophistication of the combustion control system. Because of the large geometries, the location of the sampling site is important in order to obtain a representative sample. Boiler load characteristics typically require operation with considerable burner modulation. Among the instruments often available are continuous monitors for excess O_2 and CO_2, CO, NO_x, opacity, and stack temperature.

The "minimum O_2 level" determined for an existing unit should be compared with typical values given in Attachment 17-11. A value which is higher than the range shown may result from burner malfunctions or other fuel or equipment-related problems. Note also that many burners will exhibit higher "minimum O_2" at lower firing rates.

The recommended operational value for excess air is called the "lowest practical excess air," a value 0.5 to 2.0% greater than the minimum excess air described above. The extra excess air is required to accommodate operating variables at a particular installation, such as variation in fuel properties, rapid burner modulation, variation in ambient conditions, and "play" in automatic controls. Changes in air flow rate resulting from barometric pressure changes may be accommodated by the lowest practical excess air. Other ambient variations, such as changes in temperature and wind, may be minimized if the unit is located inside a building. Units located outside may require additional excess air or sophisticated combustion control systems (5).

The above-mentioned adjustments procedures for minimizing excess air typically will improve thermal efficiency and reduce NO_x emissions. However, as was discussed in Chapter 16, more extensive design modifications may be required for considerable NO_x control. These will be discussed in the next sections.

Industrial Boiler Combustion Modifications

Industrial boiler manufacturers can adopt important combustion design modification techniques for reducing NO_X emissions. From Attachment 17-12, one may conclude that NO_X emissions depend on the fuel, the excess air, and the design of the particular installation.

In general, NO_X emissions from coal, characterized mainly by fuel NO_X, are very sensitive to excess oxygen. The NO_X from fuel oil is sensitive to excess oxygen, but less so than coal, because of the lower nitrogen in oil. The NO_X emissions from natural gas, characterized as thermal NO_X, are typically lower than for coal or oil. This is due to very low nitrogen content of gas and because burning is more uniform with fewer hot spots. Note in Attachment 17-12 that some gas-fired units may show an increase of NO_X with decreasing excess oxygen. This is because of the increasing combustion temperatures.

Staged combustion has been demonstrated as an effective combustion modification technique for NO_X control of an oil or gas-fired 40,000 lb/hr water tube boiler (see Attachment 17-13). Burners were operated on less than stoichiometric air, with the balance of the air being provided through special NO_X ports. The corresponding NO_X control for gas and oil firing is shown in Attachments 17-14 and 17-15. The location and air velocity in the NO_X ports influence the degree of NO_X control, as it is possible to create hot spots with rapid air injection. Note in Attachment 17-16, however, that thermal efficiency is usually reduced with this technique.

Reduced combustion air temperature has been shown to be effective for NO_X control on three water tube boilers burning gas and/or No. 6 fuel oil. This is shown in Attachment 17-17. Note, however, that reduced air preheat is effective for coal combustion only if high excess air is used, as illustrated in Attachment 17-18. Generally, lower thermal efficiency occurs with reduced combustion air preheat since energy recovery devices are not used, as illustrated in Attachment 17-19.

Flue gas recirculation, FGR, is an effective technique for NO_X control in industrial boilers, particularly for those using natural gas (9, 10). As more flue gas is recirculated, the NO_X control effect becomes greater, as illustrated in Attachment 17-20. Notice that the effects appear to be dependent on the particular combustion equipment design. The recirculated flue gases may be delivered with the primary air, the secondary air, or the total air. It may be possible to obtain some improved thermal efficiency with flue gas recirculation; but this is probably not a cost-effective method of NO_X control.

Utility Boiler Combustion Modification

NO_X control effectiveness for utility boiler depends on furnace design characteristics (geometry and operational flexibility), fuel-air handling systems, automatic controls, and the operational problems that result from combustion modifications (11). Modifications are limited by the emission of other pollutants (CO, smoke, and carbon in flyash), the onset of slagging and fouling, and flame stability problems.

Depending on the NO_X emission limits to be reached, combustion modification should proceed in stages. First, the combustion conditions should be fine-tuned by lowering excess air through adjustment of burner settings and air distribution. Second, soot-blowing frequency should be increased to improve flame heat transfer. This will lower the maximum combustion temperature. Next, consider implementing two-stage combustion through burner-biased firing or burner-out-of-service. The final stage would include major retrofit changes, such as including overfire air ports, flue gas recirculation, and new burners.

Gas-fired utility boilers produce only thermal NO_X, which is the easiest to control by combustion modification. As Attachment 17-21 indicates, larger units tend to produce more NO_X because of the higher combustion temperature (thermal NO_X). Low excess air is used routinely in gas-fired utility boilers for NO_X control. This reduction, however, depends on furnace design and firing method. Generally, a slight increase in thermal efficiency is noted, and flame stability is not a serious problem.

Two-stage combustion with flue gas recirculation, shown in Attachments 17-21 and 17-22, results in substantial NO_X control for gas-fired utility boilers. Overfire air, biased firing, and burners-out-of-service are effective designs for achieving off-stoichiometric combustion.

Oil-fired utility boilers produce fuel NO_X as an important part of the total NO_X. As expected, low excess air is used routinely in oil-fired burners for NO_X control, as well as improve thermal efficiency and to reduce the conversion of SO_2 to SO_3. Larger residual oil-fired units do not appear to produce more NO_X than smaller units, illustrated in Attachment 17-23. This is an indication of the importance of fuel NO_X as opposed to thermal NO_X in oil-fired units.

Overfire air ports, shown in Attachment 17-24, are the accepted technique for providing two-stage combustion in wall-fired oil-burning units. Burners-out-of-service in the upper part of the firing pattern is used for NO_X control in wall and tangentially fired oil units. The effect of combining two-stage combustion with flue gas recirculation is shown in Attachment 17-25. NO_X reductions of 40 to 60% have been demonstrated, but this may require de-rating the unit in order to be successful. Also with flue gas recirculation, flame stability problems may occur at higher burner velocities.

Coal burned in utility boilers contains fuel-bound nitrogen, which accounts for up to 80% of the NO_X emitted by the stack. Wall-fired burners may obtain reduced NO_X through modifications such as low excess air, staged firing, load reduction, and flue gas recirculation. However, the latter is much less effective with coal-firing than with oil or gas.

Tangentially-fired boilers with overfire air emit considerably less NO_X than normally operated boilers, as illustrated in Attachment 17-26. Off-stoichiometric firing is an effective additional combustion modification for NO_X control, as shown in Attachment 17-27. However, fuel-rich burner conditions can produce excessive smoke and CO and flame instability.

It is unfortunate that NO_X emissions from coal-fired utility boilers are so great even after combustion modification. It appears that NO_X emissions will be of increasing regulatory concern because coal supply creates incentives for increased burning of coal. Consequently, as mentioned in Chapter 16, considerable research is now directed toward the development of adequate NO_X flue gas treatment, as well as coal-cleaning and fluidized-bed coal combustion techniques.

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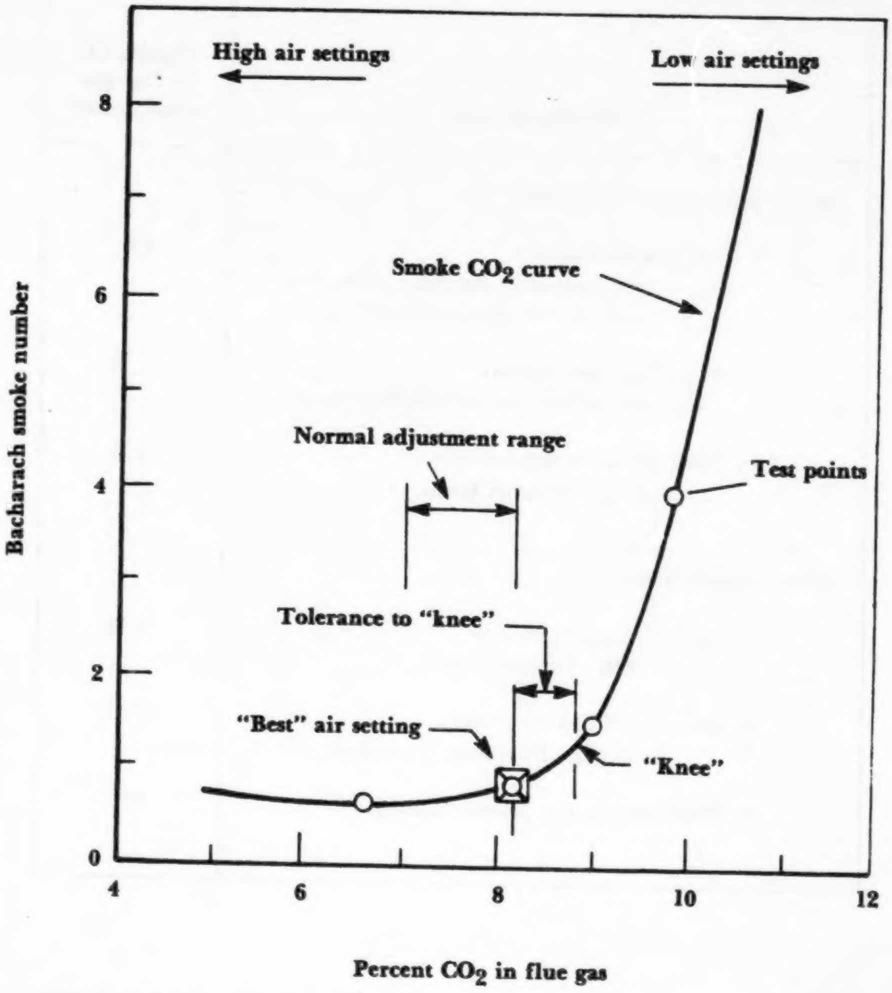
2. "Guidelines for Residential Oil-Burner Adjustments," Report No. EPA-600/2-75-069-a, Industrial Environmental Research Laboratory, USEPA (October 1975).
3. "Guidelines for Burner Adjustments for Commercial Oil-Fired Boilers," Report No. EPA-600/2-76-008, Industrial Environmental Research Laboratory, USEPA (March 1976).
4. "Guidelines for Industrial Boiler Performance Improvement," Report No. EPA-600/8-77-003a, Industrial Environmental Research Laboratory, USEPA (January 1977).
5. Reed, R. D., *Furnace Operations*, Gulf Publishing Co., Houston (1976).
6. "Reference Guideline for Industrial Boiler Manufacturers to Control Pollution with Combustion Modification," Report No. EPA-600/8-77-003b, Industrial Environmental Research Laboratory, USEPA (November 1977).
7. Cato, G. A., et al., "Reduction of Pollutant Emissions from Industrial Boilers by Combustion Modification," paper no. 76-WA/FU-5, presented at ASME Winter Annual Meeting in New York City (December 1976).
8. Crawford, A. R., et. al., "Control of Utility Boiler and Gas Turbine Pollutant Emissions by Combustion Modification Phase 1," Report No. EPA-600/7-78-036a, Industrial Environmental Research Laboratory, USEPA (March 1978).
9. Hunter, S. C., et al., "Evaluation of Two Industrial Boilers with Combustion Modification for Reduced Pollution Emission," paper no. 77-WA/APC-1, presented to ASME Winter Annual Meeting in Atlanta, Ga. (December 1977).
10. Carter, W. A., et. al., "Emission Reduction on Two Industrial Boilers with Major Combustion Modifications," Report No. EPA-600/7-78-009a, Industrial Environmental Research Laboratory, USEPA (June 1978).
11. "Control Techniques for Nitrogen Oxides Emissions from Stationary Sources," Second Edition, Report No. EPA-450/1-78-001, Office of Air Quality Planning and Standards, USEPA (January 1978).

Attachment 17-1. Typical smoke-CO_2 characteristic plot for a residential oil burner[2]



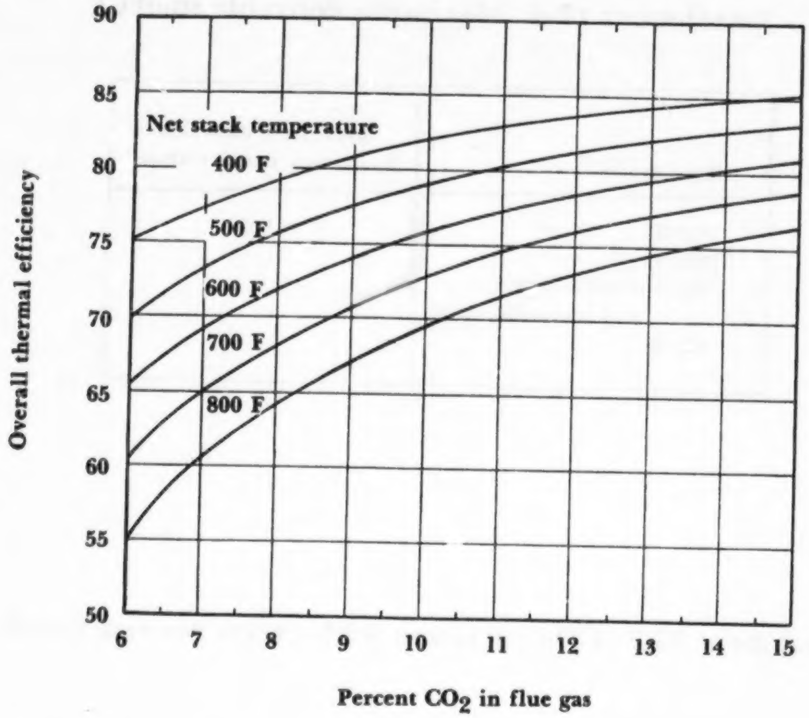
Attachment 17-2. Typical aid adjustments for different types of residential burners[2]

Oil-burner type	Typical CO in flue gas when tuned*
High-pressure gun-type burners	
• Old-style gun burners – No internal air-handling parts other than an end cone and stabilizer	8%
• Newer-style gun burners – special internal air-handling parts	9 %
• Flame-retention gun burners – flame-retention heads	10 %
Other types of burners	
• Atomizing rotary burners – ABC, Hayward, etc.	8 %
• Rotary wall-flame burners – Timkin, fluid-heat, Torridheet, etc.	12 %
• Miscellaneous low-pressure burners	**

* Based on accpetable Bacharach smoke – generally No. 1 or trace, but not exceeding No. 2. Caution should be used in leaving burners with CO_2 level higher than 13%.

** See manufacturer's instructions.

Attachment 17-3. Effect of stack temperature and CO_2 on thermal efficiency



Basis:
- Continuous operation
- No. 2 heating oil
- Heat lost from jacket is assumed to be useful heat.

Source: Bulletin 42, University of Illinois, Engineering Experiment Station Circular Series 44 (June 1942).

Attachment 17-4. Usual range of firing viscosity[3]

Atomization method	Viscosity saybolt seconds universal	Equivalent kinematic viscosity, centistokes
Pressure	35-150 SSU	4-32 cs
Steam or air	35-250 SSU	4-55 cs
Rotary	150-300 SSU	32-60 cs

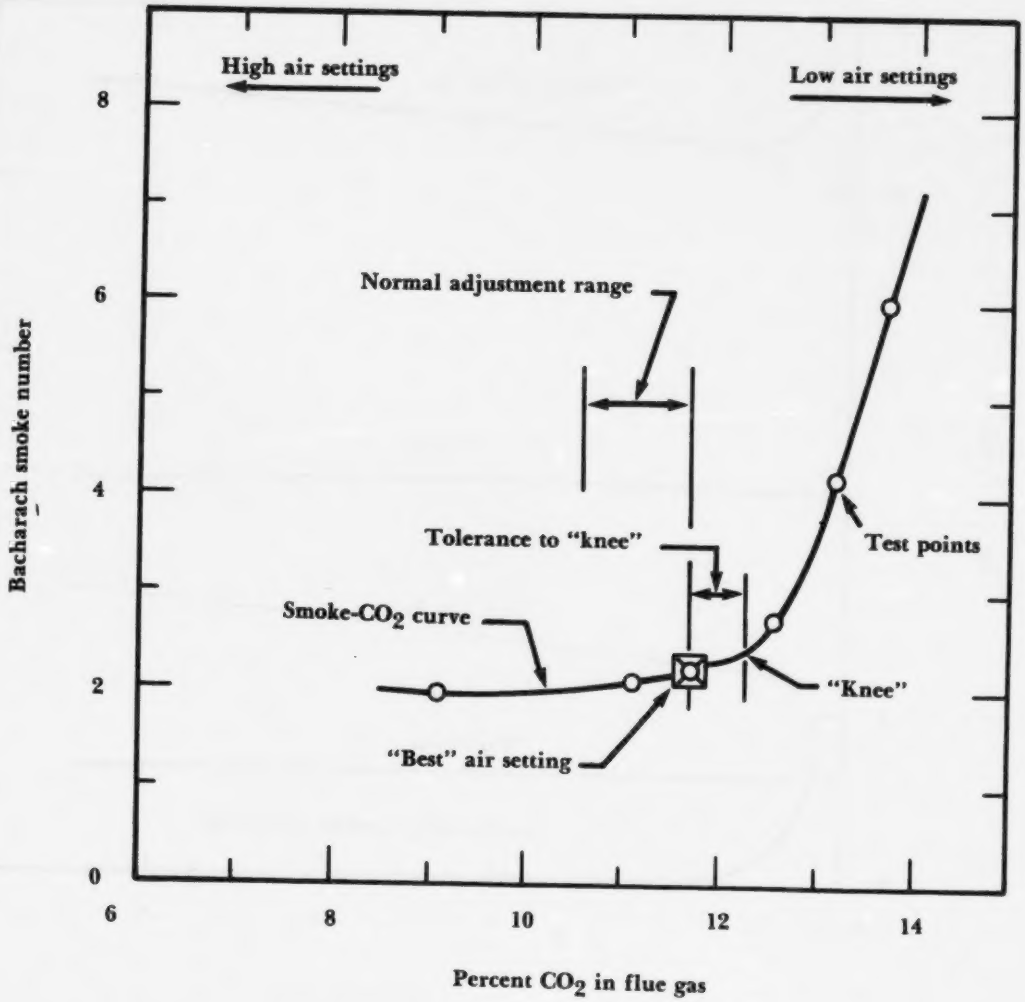
Attachment 17-6. Maximum desirable smoke[3]

Fuel grade	Maximum desirable Bacharach smoke number
No. 2	1 or less
No. 4	2
No. 5 (light and heavy), and low-sulfur resid	3
No. 6	4

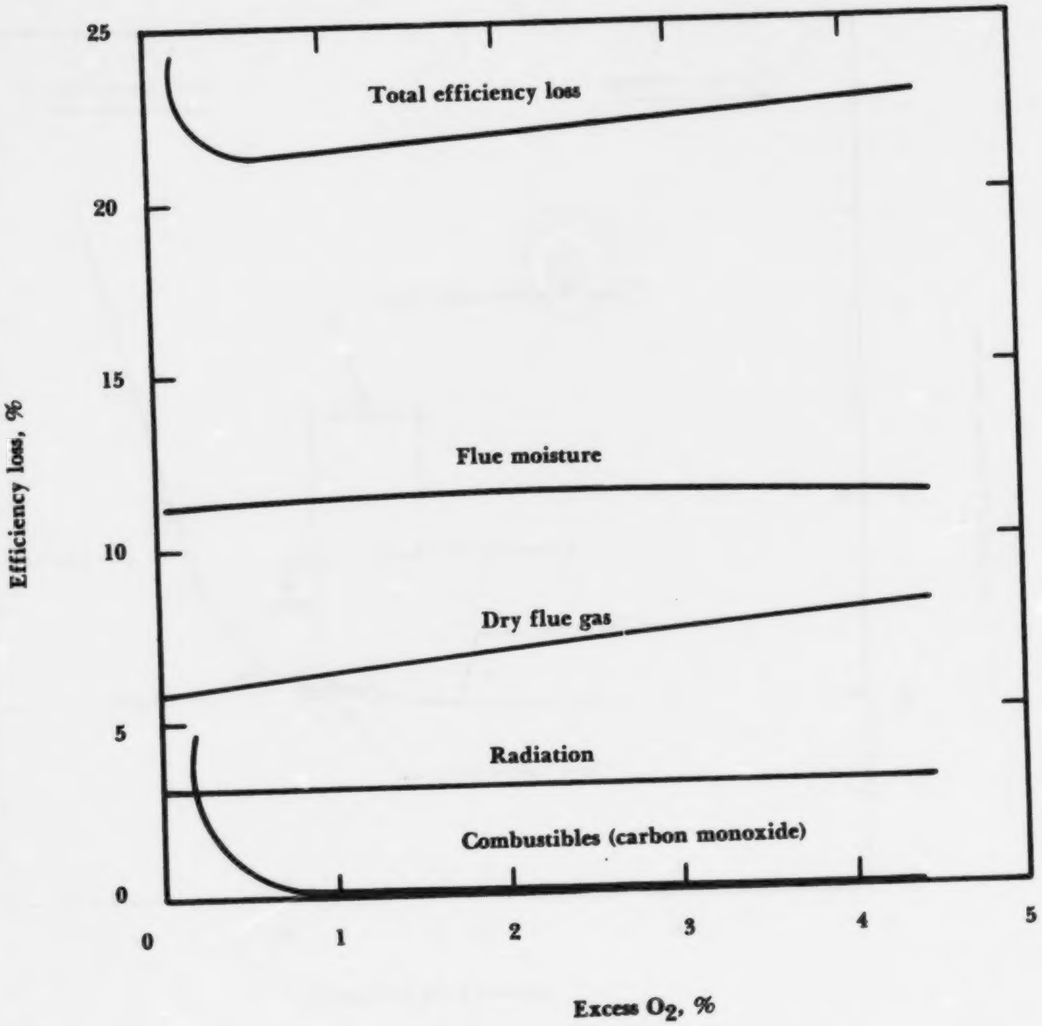
Attachment 17-7. CO_2 variation with excess air and fuels[3]

	Percent CO_2 in flue gas		
Percent excess air	Gas firing	No. 1 oil firing	No. 6 oil firing
0	12.0	15.0	16.5
10	10.8	13.5	15.0
25	9.4	11.8	13.0
50	7.9	9.8	11.0
75	6.6	8.3	9.3

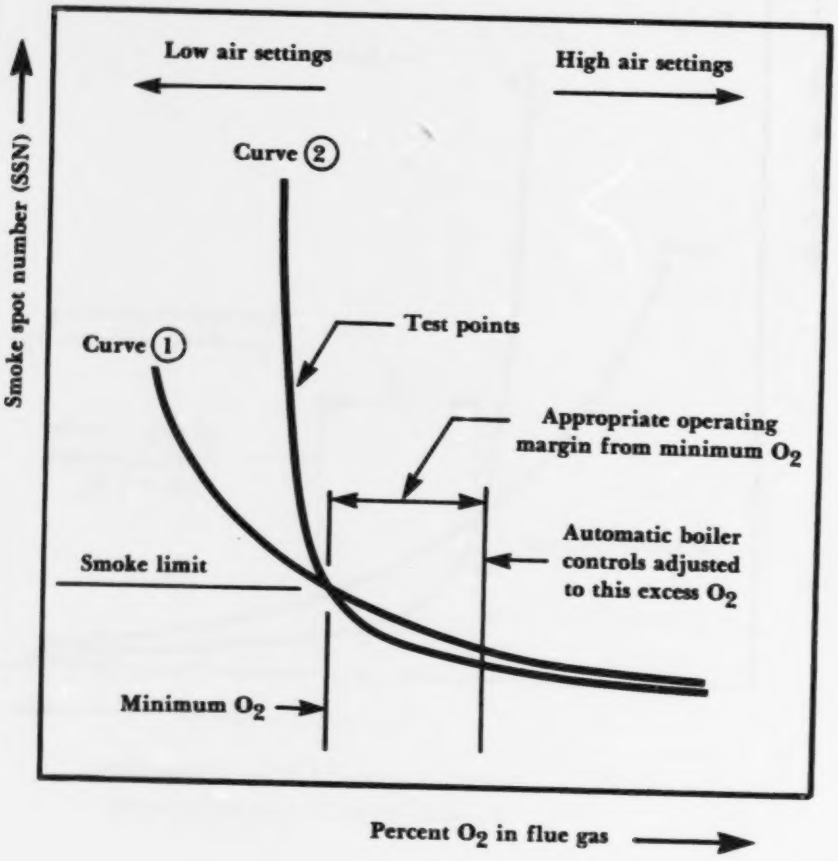
Attachment 17-5. Smoke-CO_2 characteristic for a typical commercial oil boiler firing residual oil[3]



Attachment 17-8. Variation of boiler efficiency losses with excess O_2[4]



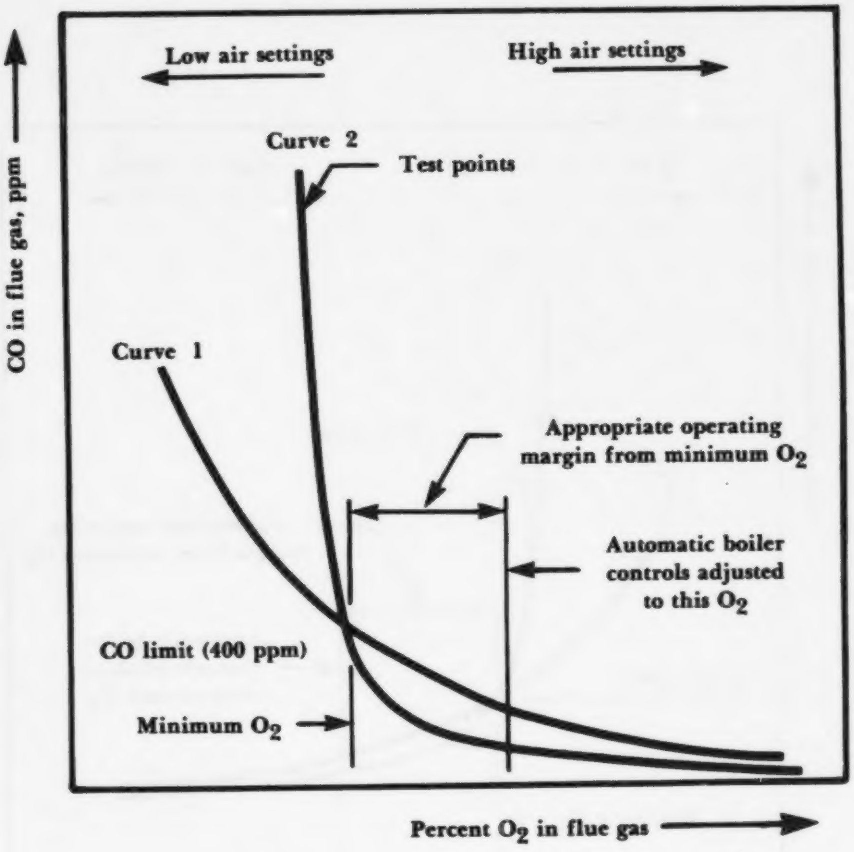
Attachment 17-9. Typical smoke-O_2 characteristic curves for coal or oil-fired industrial boilers[4]



Curve 1—Gradual smoke/O_2 characteristic

Curve 2—Steep smoke/O_2 characteristic

Attachment 17-10. Typical CO-O_2 characteristic curves for gas-fired industrial boilers[4]



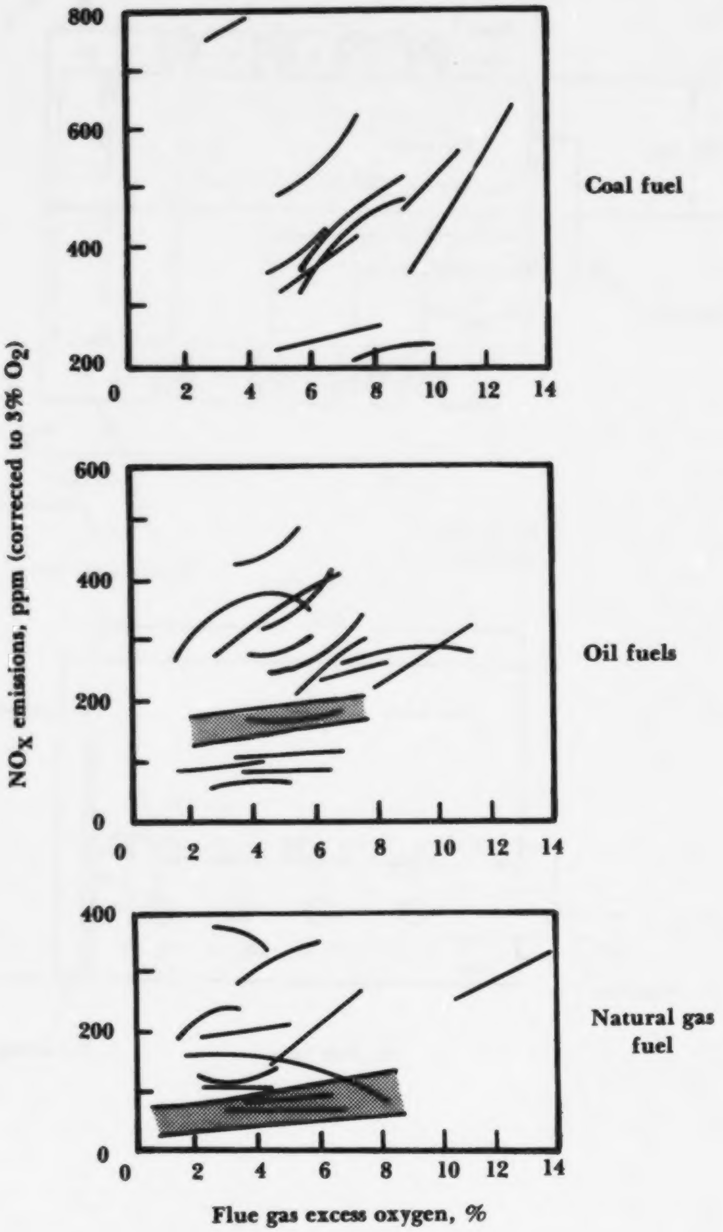
Curve 1—Gradual CO/O_2 characteristic
Curve 2—Steep CO/O_2 characteristic

Attachment 17-11. Variation of minimum O_2 with fuel[4]

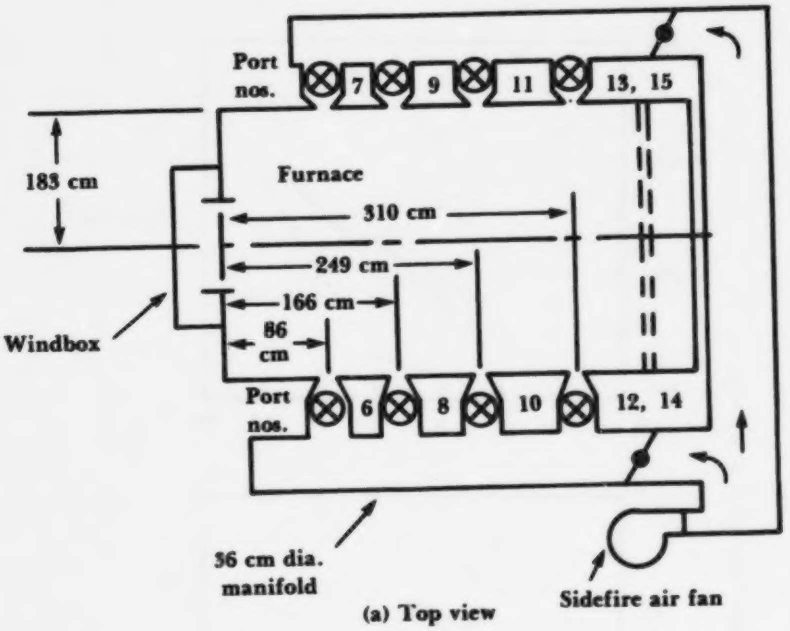
Fuel Type	Typical range of minimum excess O_2 at high firing rates
Natural gas	0.5 – 3.0%
Oil fuels	2.0 – 4.0%
Pulverized coal	3.0 – 6.0%
Coal stoker	4.0 – 8.0%

Attachment 17-12. Effect of excess oxygen and fuel on NO_X emissions[4]

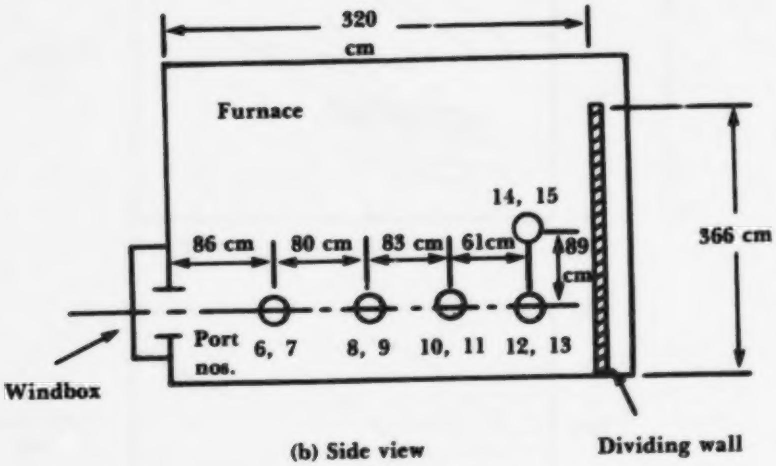
(Single lines for water-tube boilers; shaded areas for fire-tube boilers)



Attachment 17-13. Schematic diagram of staged-air system installed on a 40,000-lb/hr watertube boiler[6]

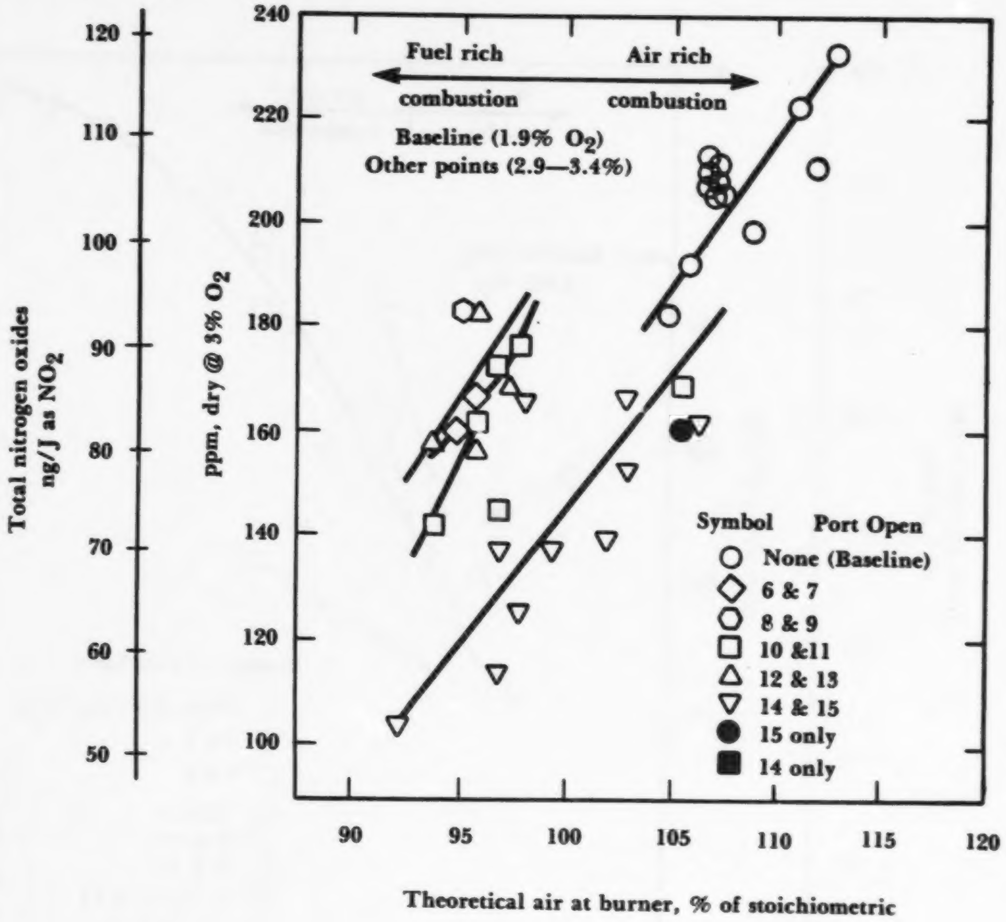

Port nos.
7
9
11
13, 15
183 cm
Furnace
310 cm
249 cm
166 cm
86 cm
Windbox
Port nos.
6
8
10
12, 14
36 cm dia. manifold
Sidefire air fan

(a) Top view

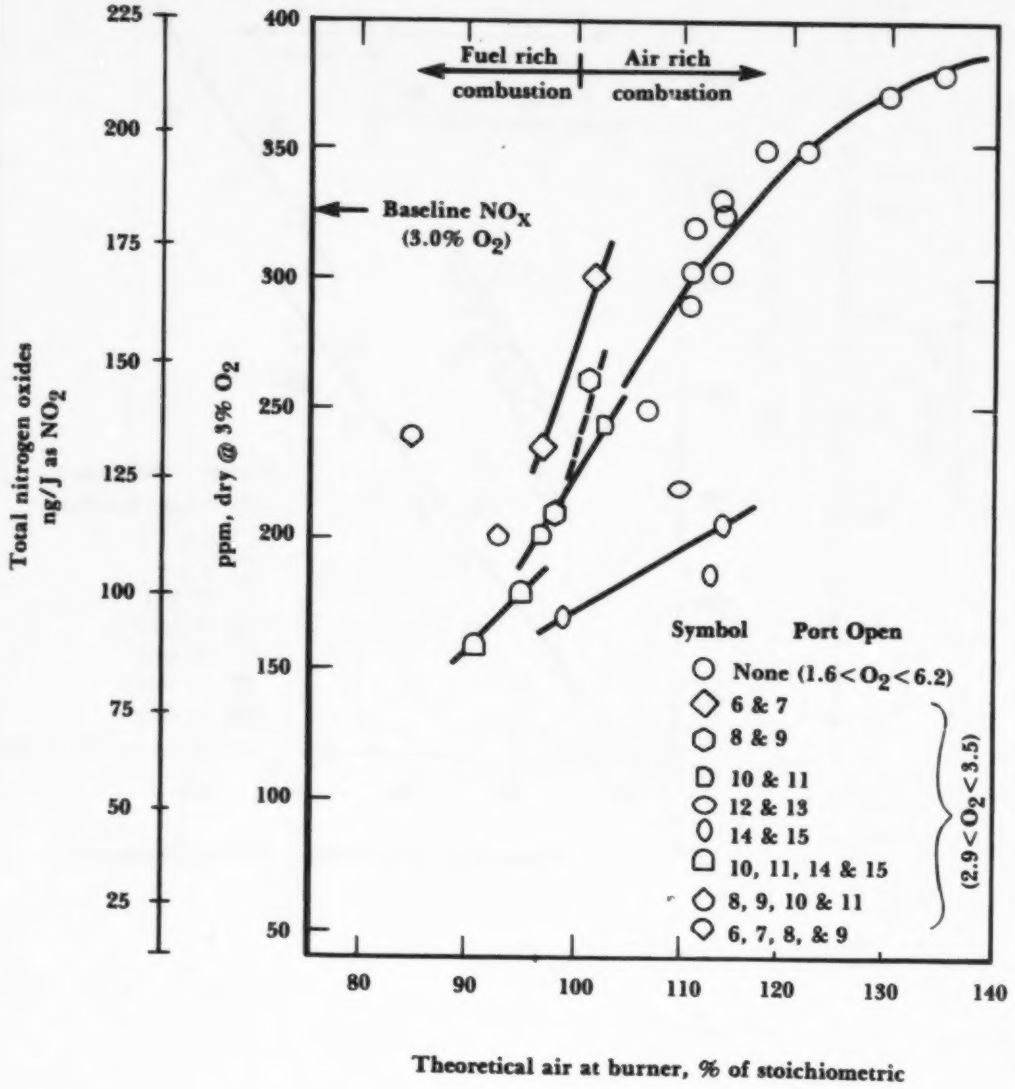

320 cm
Furnace
14, 15
86 cm
80 cm
83 cm
61cm
89 cm
366 cm
Port nos.
6, 7
8, 9
10, 11
12, 13
Windbox
Dividing wall

(b) Side view

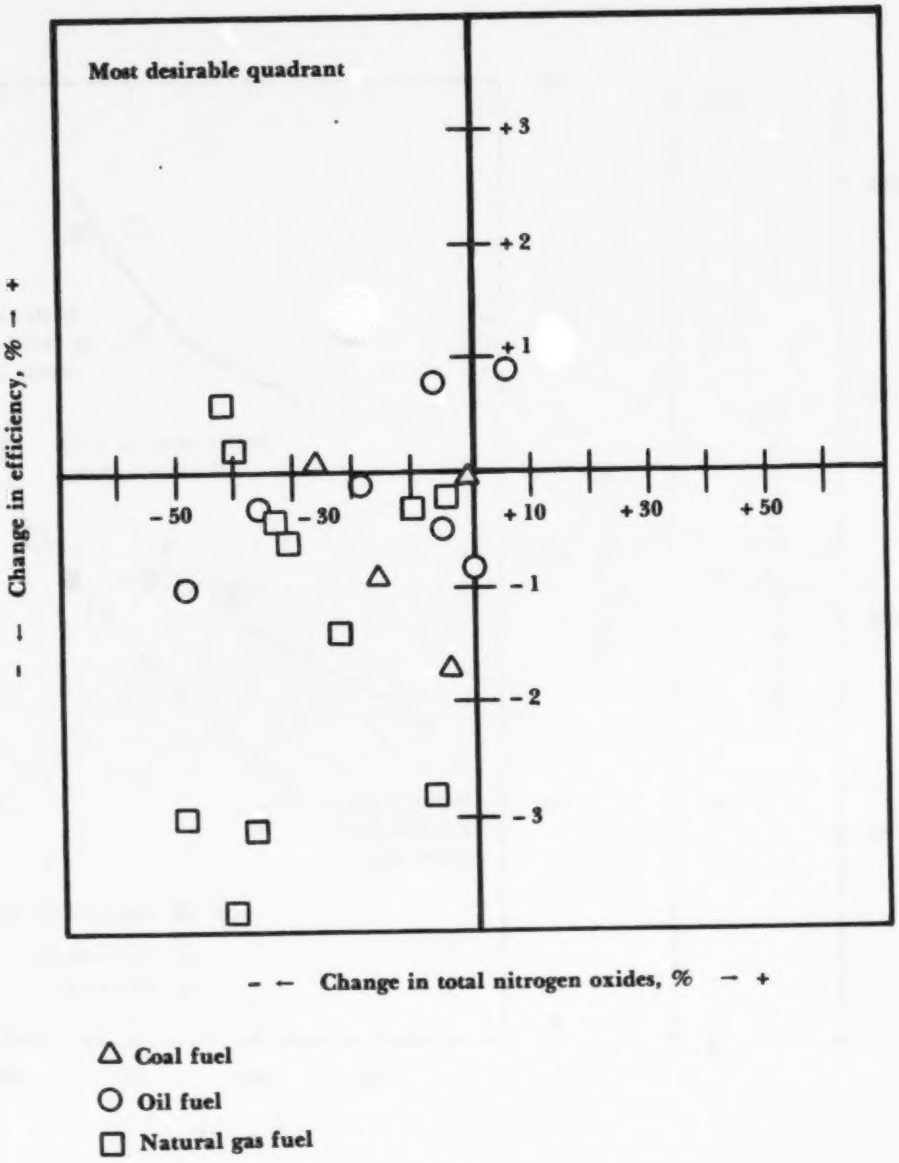
Attachment 17-14. Reduction in nitrogen oxides from staged combustion air, natural gas fuel[6]



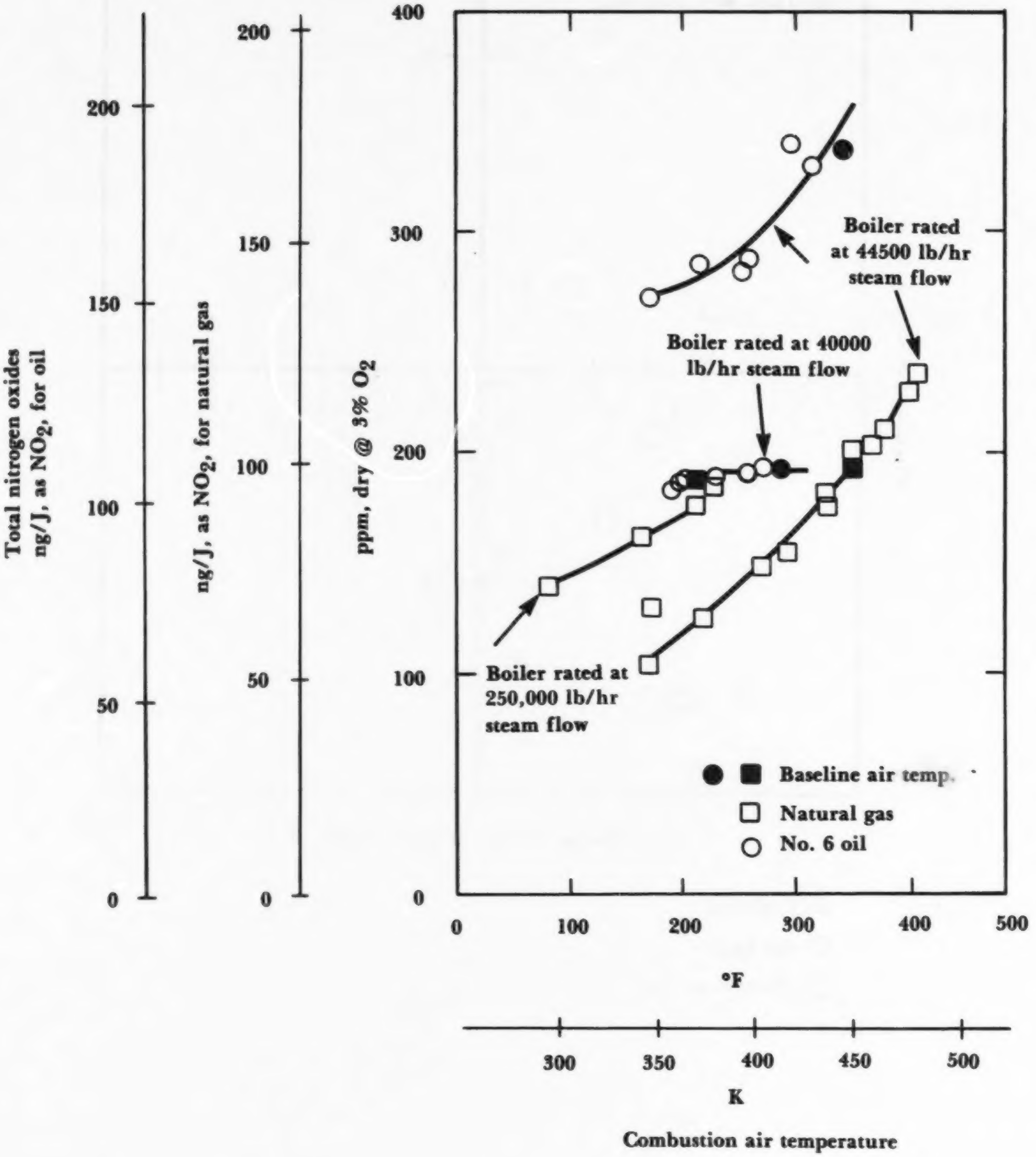
Attachment 17-15. Reduction in nitrogen oxides emissions from staged combustion air, No. 6 fuel oil[6]



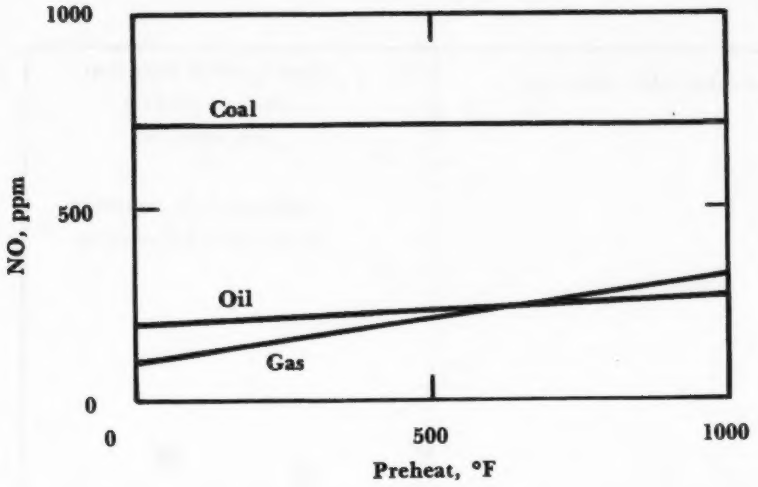
Attachment 17-16. Effect of NO_x ports on boiler efficiency[6]



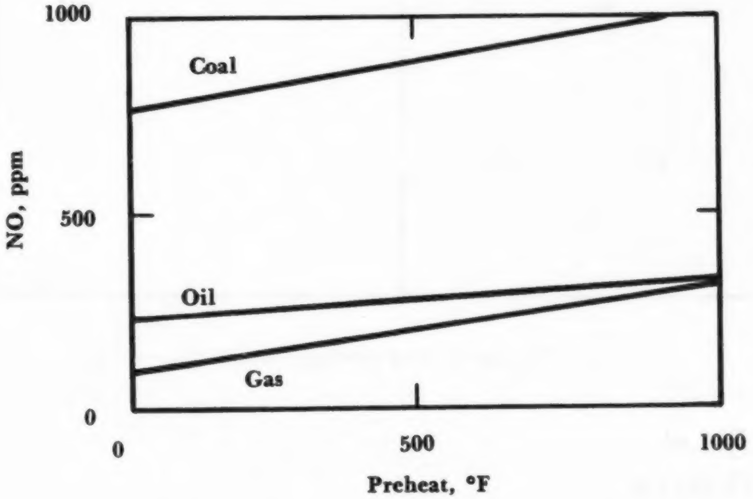
Attachment 17-17. Effect of combustion air temperature on total nitrogen oxides emissions with gas and oil fuels for three watertube boilers[6]



Attachment 17-18. NO_X control by air preheat reduction[6]

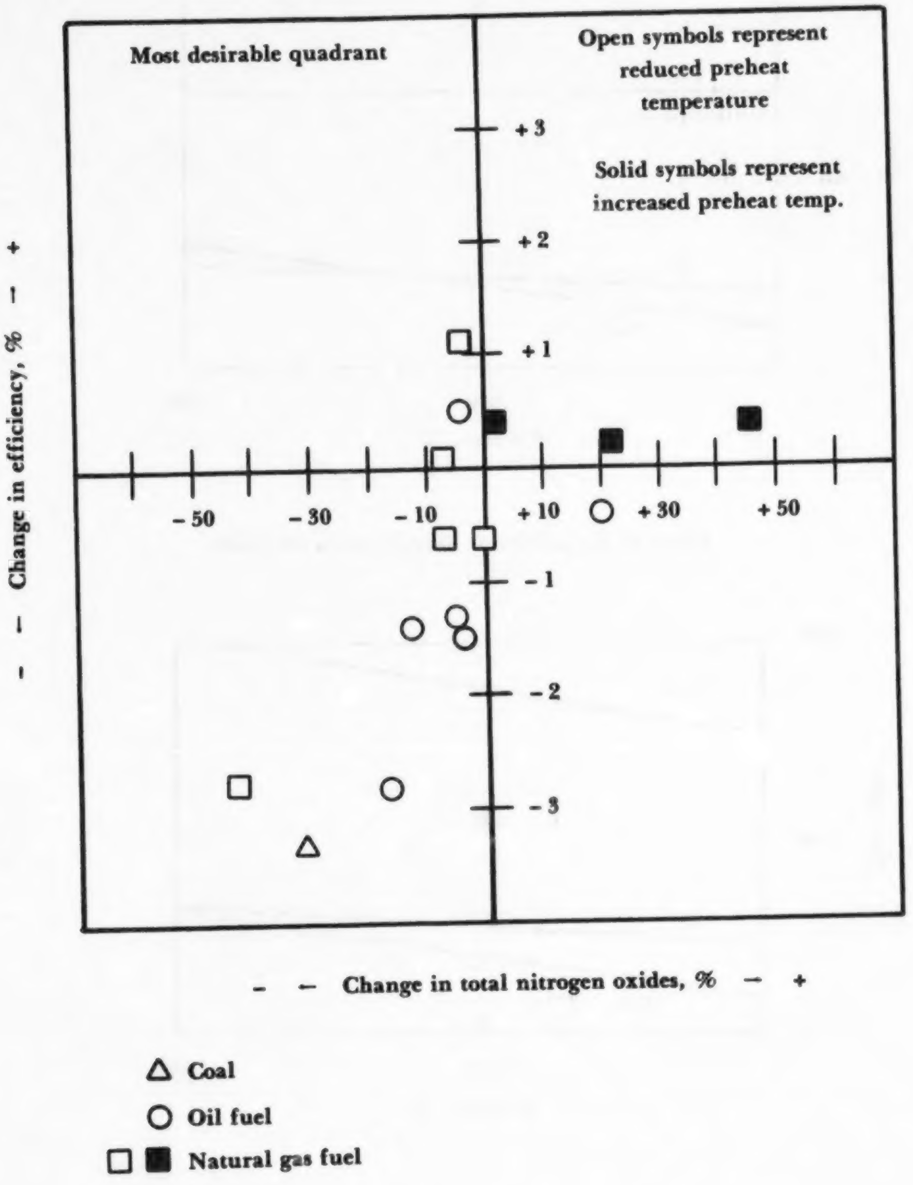


Effect of air preheat at normal excess air levels.

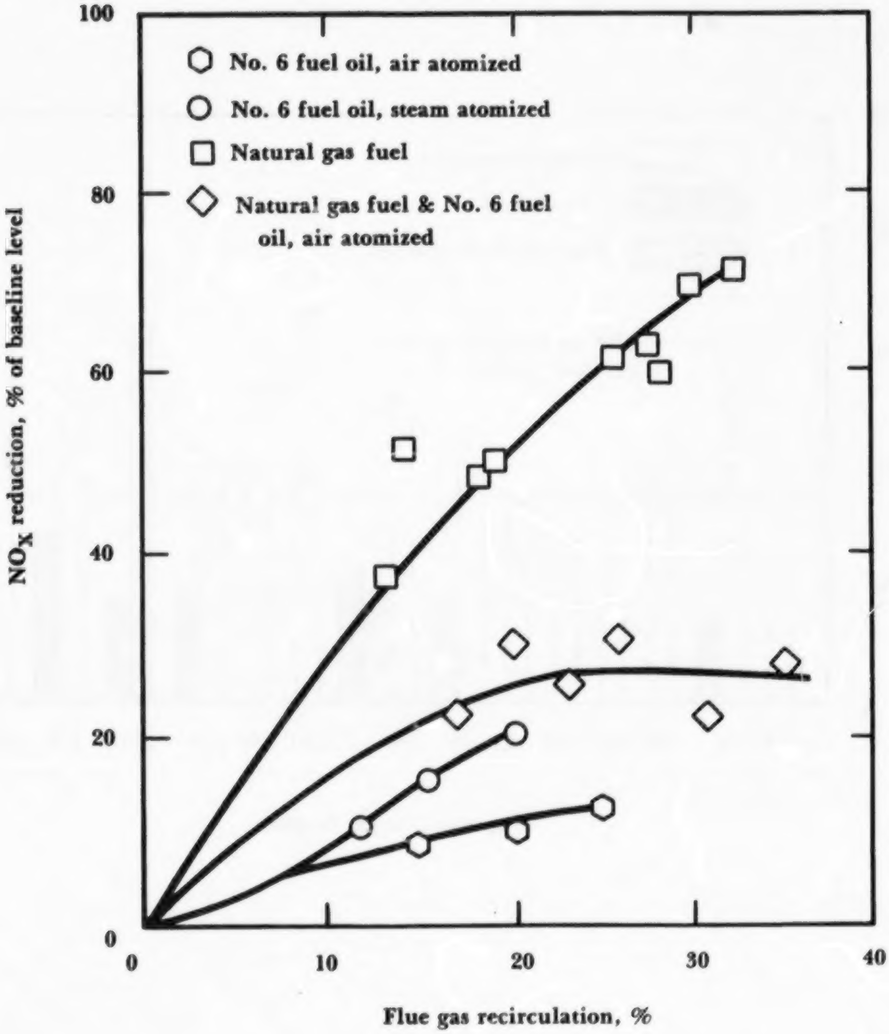


Effect of air preheat at high excess air.

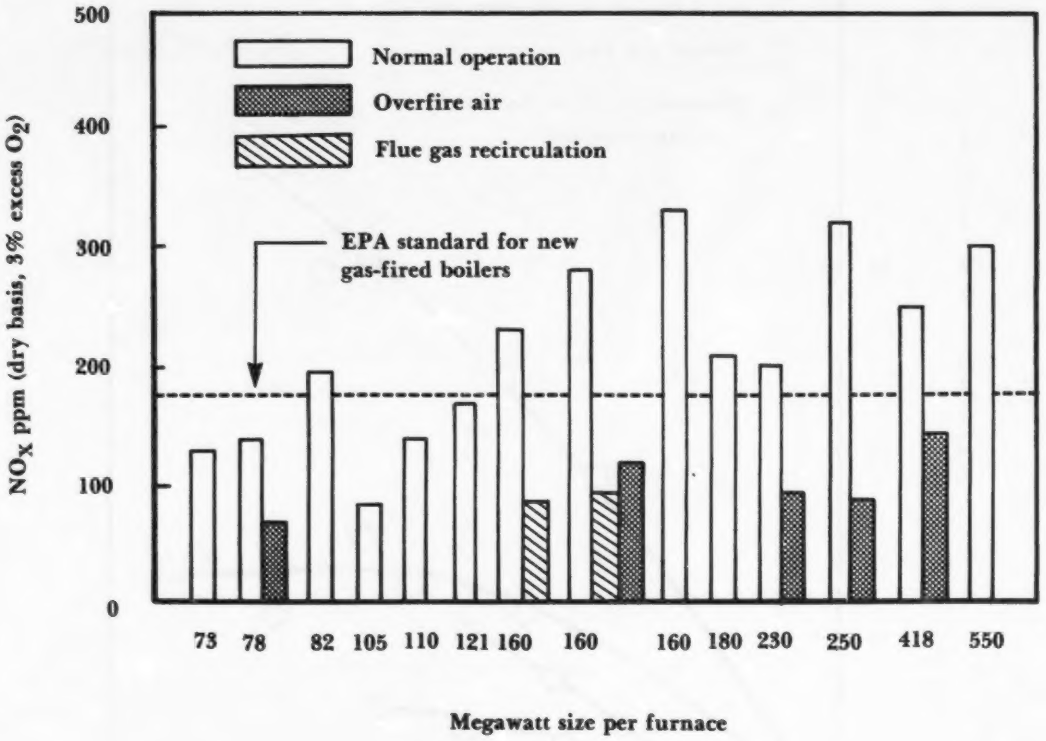
Attachment 17-19. Effect of combustion air preheat temperature on boiler efficiency[6]



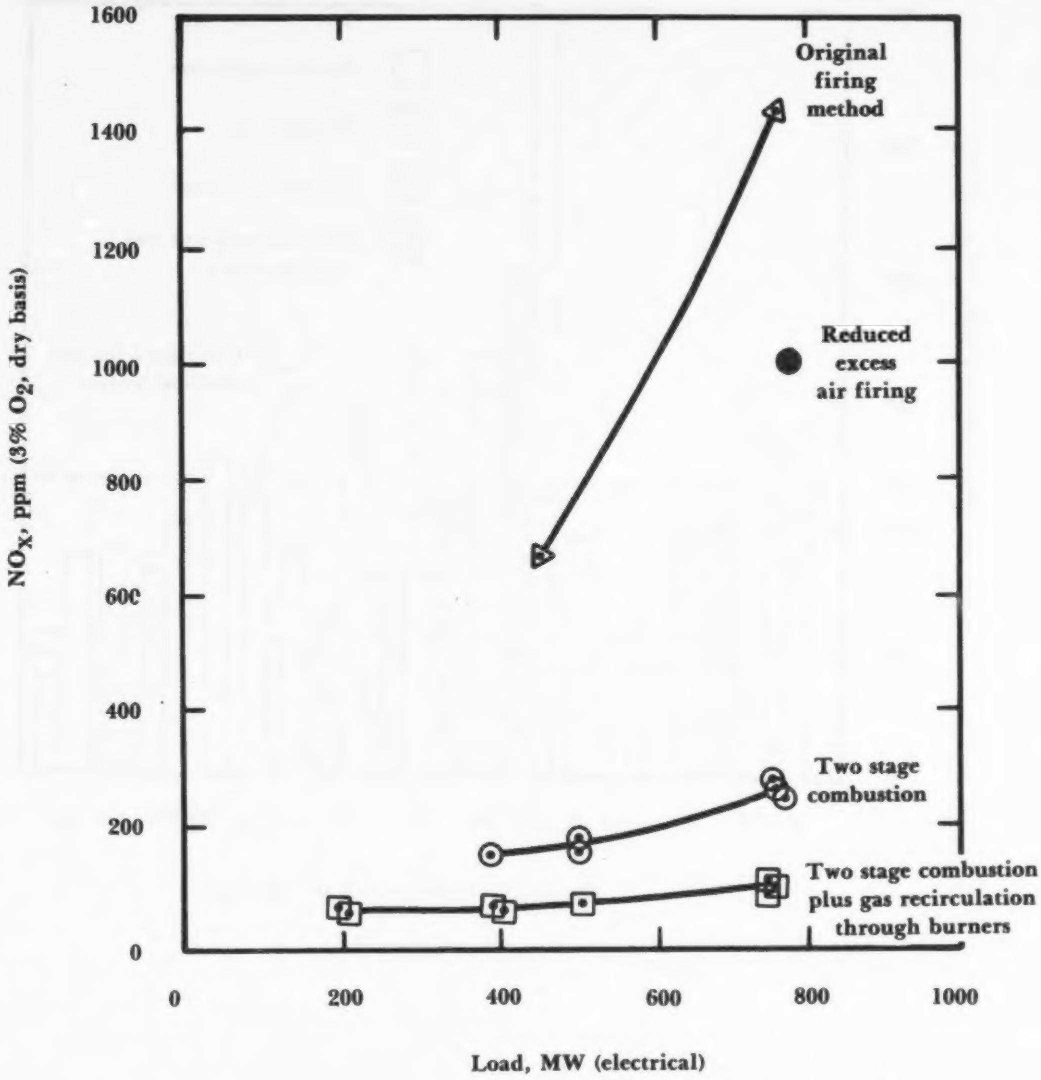
Attachment 17-20. Reduction in total nitrogen oxide emissions by flue gas recirculation with constant excess air[6]



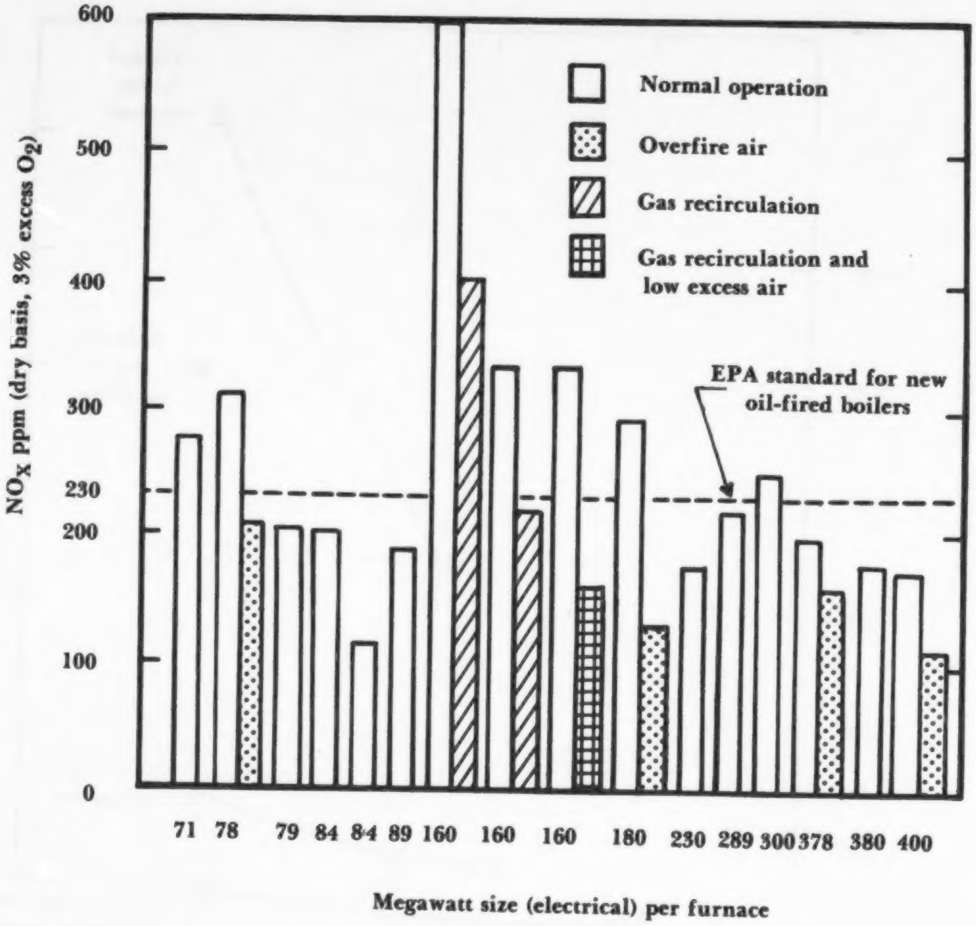
Attachment 17-21. NO_X emissions from gas, tangentially-fired utility boilers[11]



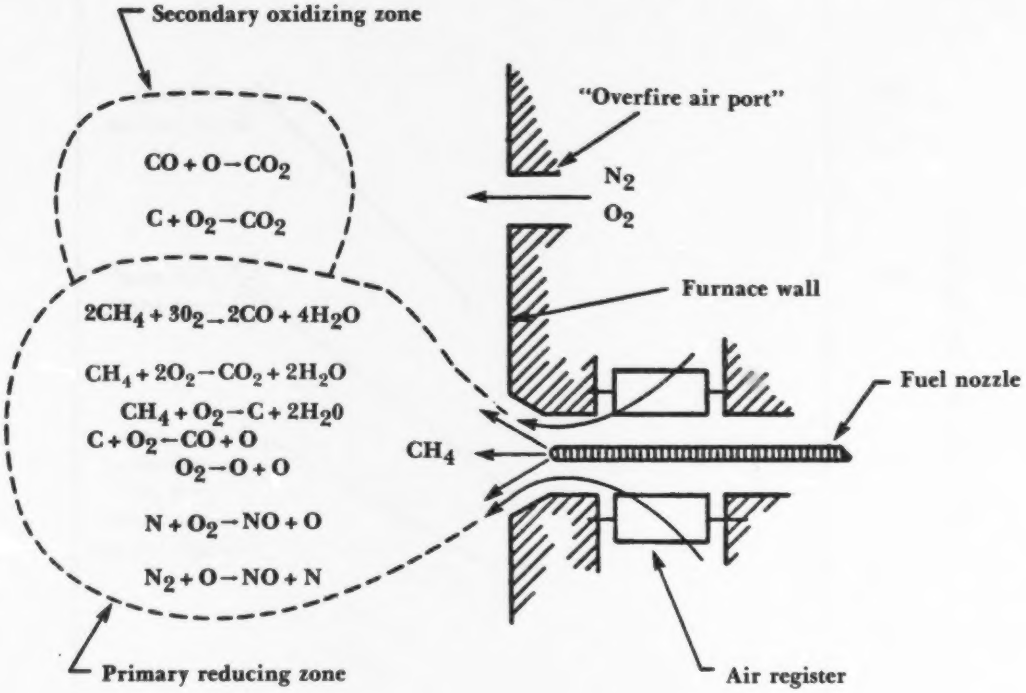
Attachment 17-22. Effects of NO_X control methods on a gas, wall-fired utility boiler[11]



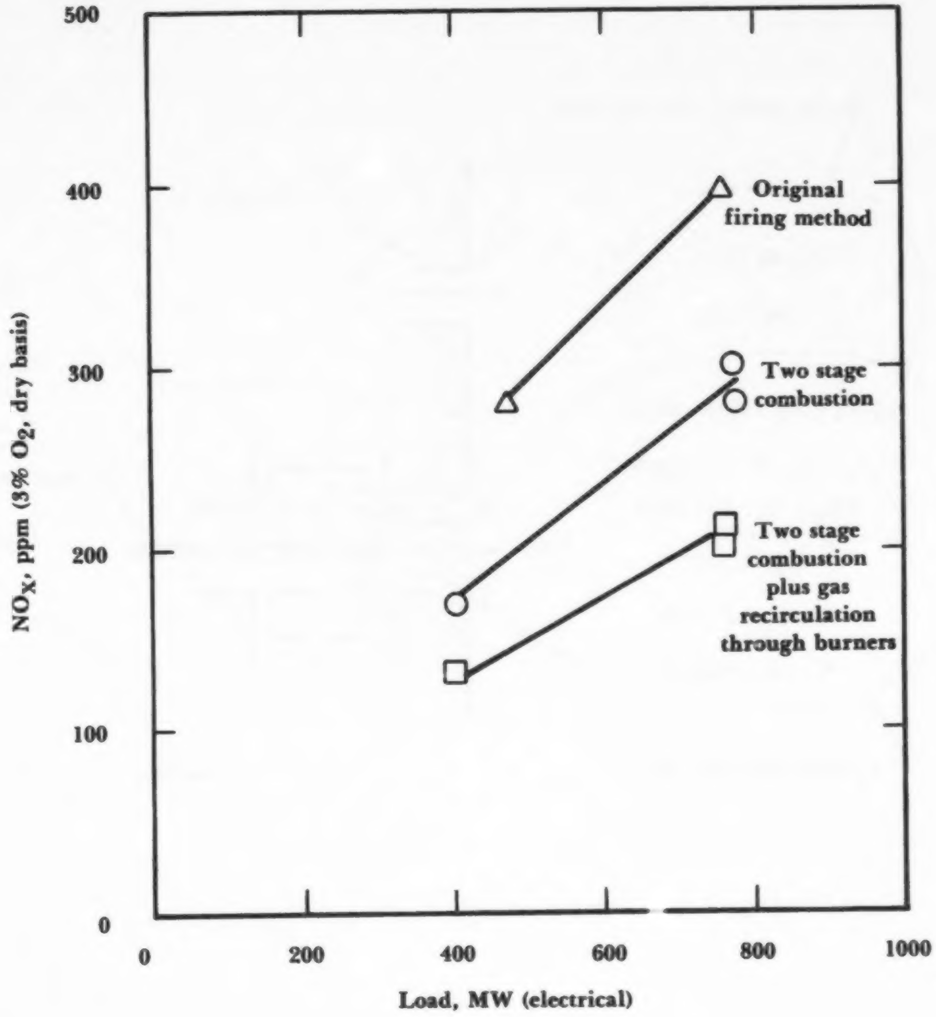
Attachment 17-23. NO_X emissions from residual oil, tangentially-fired utility boilers[11]



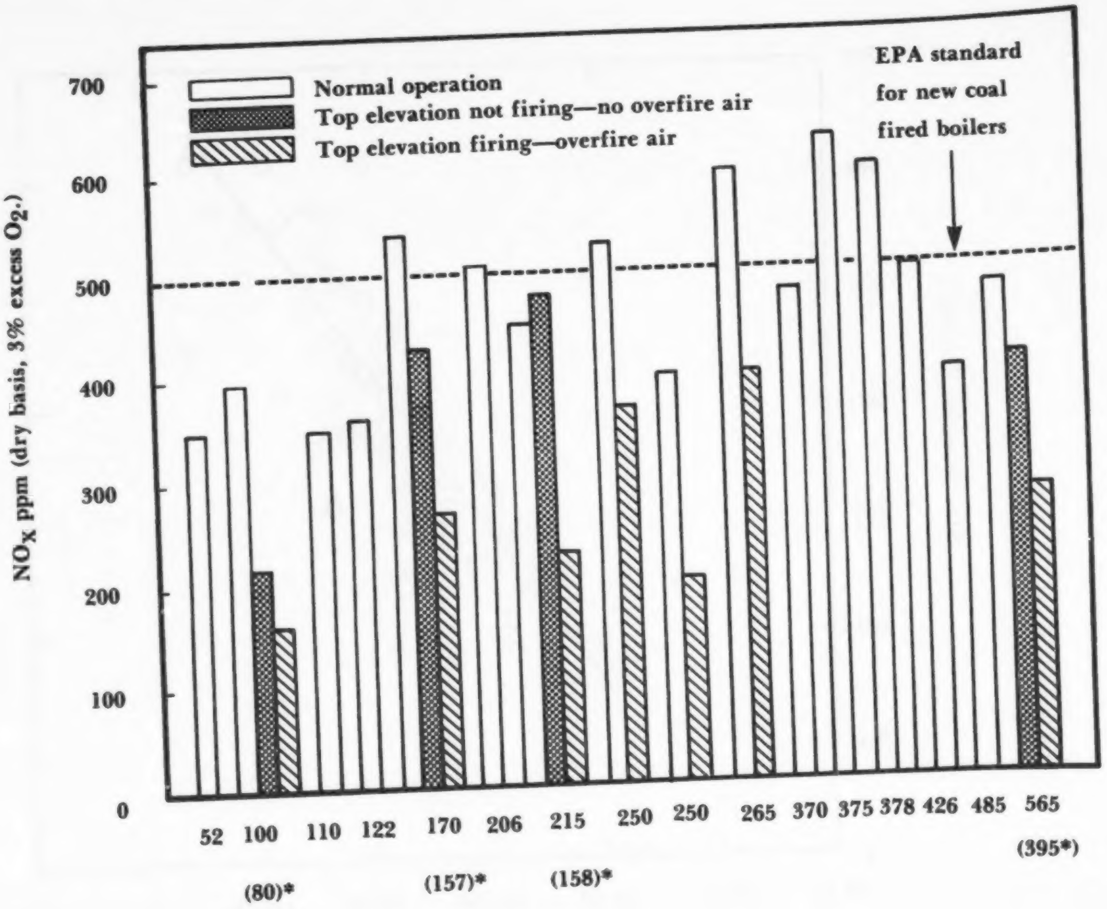
Attachment 17-24. Two-stage combustion[11]


Secondary oxidizing zone
$CO + O \rightarrow CO_2$
$C + O_2 \rightarrow CO_2$
$2CH_4 + 3O_2 \rightarrow 2CO + 4H_2O$
$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$
$CH_4 + O_2 \rightarrow C + 2H_20$
$C + O_2 \leftarrow CO + O$
$O_2 \rightarrow O + O$
$N + O_2 \rightarrow NO + O$
$N_2 + O \rightarrow NO + N$
Primary reducing zone
"Overfire air port"
N_2
O_2
Furnace wall
Fuel nozzle
CH_4
Air register

Attachment 17-25. Effects of NO_X control methods[11]

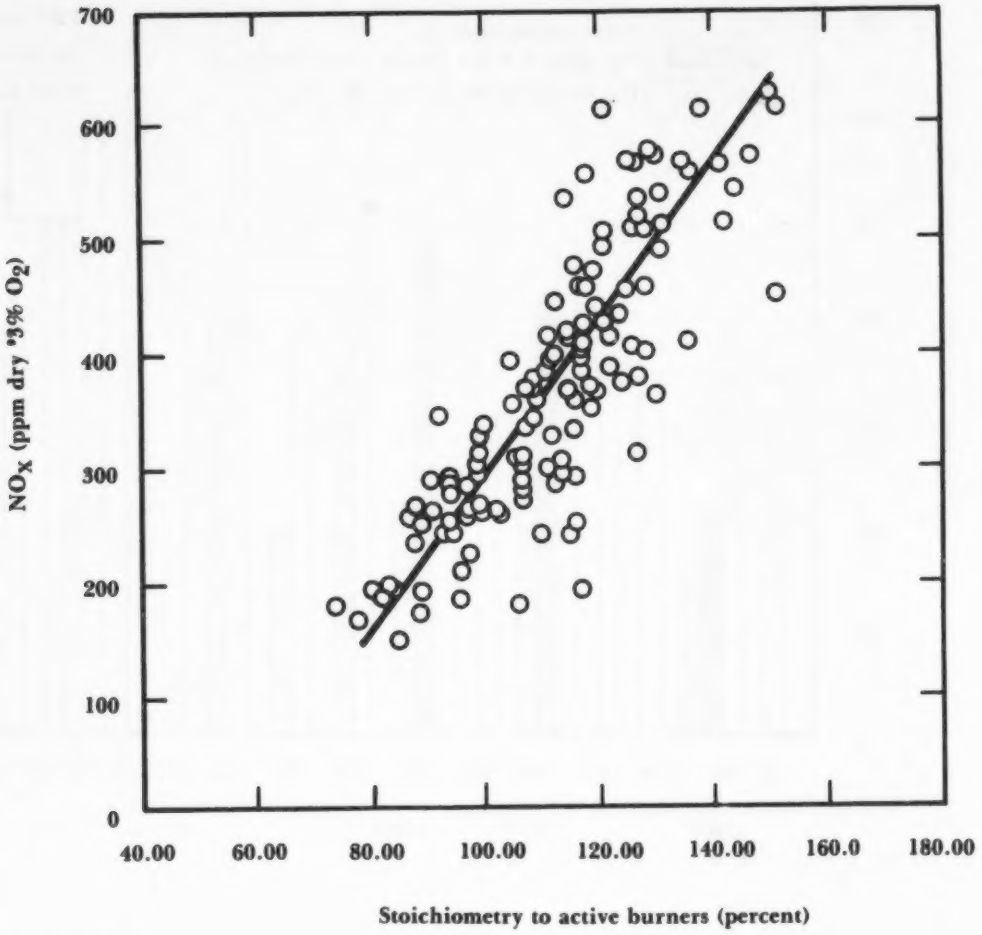


Attachment 17-26. NO_X emissions from tangential, coal-fired utility boilers[11]

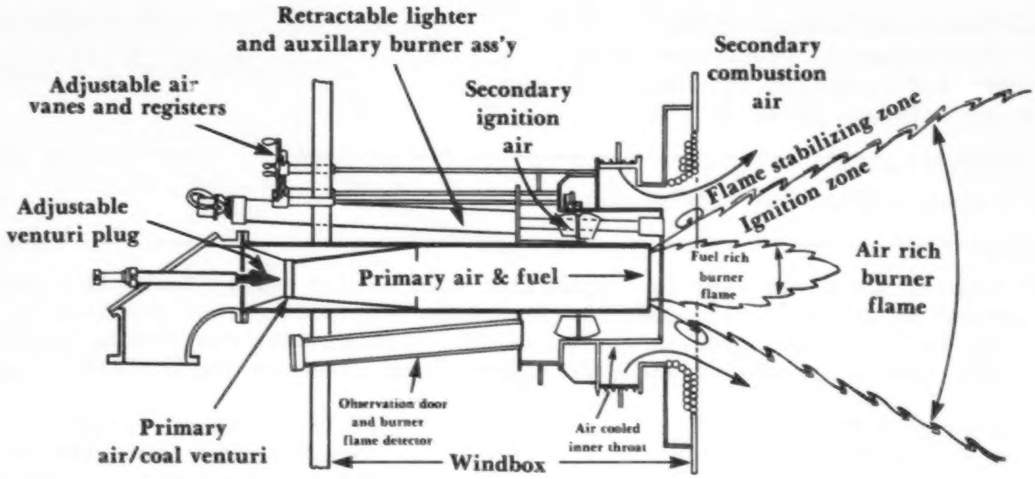


Megawatt size (electrical) per furnace
*(Reduced rating when top elevation not firing)

Attachment 17-27. Effect of burner stoichiometry on NO_X production in tangential, coal-fired boilers[11]



Attachment 17-28. Pulverized coal burner adapted for low NO_X emissions


Retractable lighter and auxillary burner ass'y
Adjustable air vanes and registers
Secondary ignition air
Secondary combustion air
Flame stabilizing zone
Ignition zone
Adjustable venturi plug
Primary air & fuel
Fuel rich burner flame
Air rich burner flame
Primary air/coal venturi
Observation door and burner flame detector
Air cooled inner throat
Windbox